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I. Introduction

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment (IMPROVE) data, which reflects monitored visibility impairment in Class I areas, the haze index for the twenty percent worst days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association (CENRAP)[1], all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards (MATS) rule[2], the continuing benefits of the Clean Air Interstate Rule (CAIR), the next phase of the Cross State Air Pollution Rule (CSAPR), and the National Ambient Air Quality Standards (NAAQS), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of the State Implementation Plan (SIP) controls, no further action will be necessary to ensure that Arkansas' Class I areas remain below the Uniform Rate of Progress (URP) until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

A. Arkansas State Implementation Plan Revision

Arkansas has made significant improvements in air quality in recent years. Arkansas is now in attainment for all of the national ambient air quality standards and is well below both the State and the EPA's 2018 regional haze reasonable progress goals. Arkansas is taking steps to revise its regional haze SIP to return control of the regional haze program to the state.

Specifically, Arkansas has included in this SIP revisions to address disapproved portions of the Arkansas Regional Haze State Implementation Plan (AR RH SIP), submitted to the United States Environmental Protection Agency (EPA) in 2008. In 2012, EPA partially approved and partially

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[1] CENRAP is a regional planning organization that includes nine states–Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[2] In spite of the Supreme Court decision in Michigan v. EPA, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units (EGUs), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, ADEQ expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

disapproved the 2008 AR RH SIP.[3] Specifically, the following elements are being submitted for EPA approval:

- BART compliance dates;
- Best available retrofit technology (BART) eligible sources and subject-to-BART Sources;
- BART determinations:
  - Sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM) BART determinations for Arkansas Electric Cooperative Corporation (AECC) Bailey Plant Unit 1;
  - SO_2, NOx, and PM BART determinations for AECC McClellan Plant Unit 1;
  - SO_2 and NOx BART determinations for Southwest Power Company (SWEPCO) Flint Creek Plant Boiler No. 1;
  - SO_2, NOx, and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4;
  - SO_2 and NOx BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
  - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
- Reasonable progress goals (RPGs); and
- Long-term strategy.

Revisions to disapproved BART requirements for Domtar Ashdown Mill are not included in this SIP revision. The remaining provisions of the 2008 AR RH SIP were approved. Arkansas is not revising portions of the 2008 AR RH SIP that were approved.

B. Arkansas SIP Components Included in this Revision

The following Administrative Orders (AOs) are included in this SIP revision:

- LIS No. [To be assigned upon finalization] between Entergy and ADEQ
- LIS No. [To be assigned upon finalization] between SWEPCO and ADEQ
- LIS No. [To be assigned upon finalization] between AECC and ADEQ

Inclusion of permanently enforceable emissions limitations and compliance schedules in the included AOs is consistent with and allowable under federal programs.

Sampling, monitoring, and reporting requirements that are generally applicable to stationary sources, including sources for which emissions limitations are established in this SIP, are contained in SIP-approved Arkansas Pollution Control and Ecology Commission (APC&EC) Regulation No. 19 Chapter 7. No revisions to requirements in Regulation No. 19 Chapter 7 were necessary for this SIP revision.

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[3] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

II. Background

In 1977, Congress added § 169 to the Clean Air Act (CAA), which set forth the following goal for restoring pristine conditions in national parks and wilderness areas:

Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.

In 1980, EPA issued regulations to address visibility degradation that is "reasonably attributable" to a single source or small group of sources. These regulations primarily addressed "plume blight"—visual impairment of air quality that manifests itself as a coherent plume—rather than overall haze. In 1988, EPA, the states, and federal land managers (FLMs) began monitoring fine particulate matter concentrations and visibility in thirty Class I areas to better understand the species of particulates causing visibility impairment.

When the CAA was amended in 1990, Congress added § 169(B) which authorized research and regular assessments of progress toward restoring visibility in Class I areas and authorized the creation of visibility transport regions and commissions. Specifically, CAA § 169(B)(f) mandated the creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to EPA for regions affecting the visibility of the Grand Canyon National Park. EPA relied upon the recommendations of GCVTC and research reports to develop the 1999 "Regional Haze Regulations: Final Rule" (RHR).[4]

The 1999 RHR sought to address the combined visibility effects of various pollution sources over a wide geographic region with the goal of achieving natural visibility conditions at designated Class I areas by 2064. This required all states, including those that did not have Class I areas to participate in planning, analysis, and emission control programs under the RHR. States with Class I areas were required to conduct certain analyses to establish goals for each Class I area in the state to 1) improve visibility on the haziest days and 2) ensure no degradation occurs on the clearest days. These goals and long-term strategies to achieve these goals were to be included in SIPs covering each ten-year period leading up to 2064. States were also required to submit progress reports in the form of SIP revisions every five years. The 1999 RHR also expanded the existing Class I visibility monitoring network to 108 Class I areas.

For the purposes of assisting with coordination and cooperation among states to address visibility issues, EPA designated five regional planning organizations (RPOs) to assist with coordination and cooperation among states in addressing visibility issues the states have in common. Arkansas was located in the CENRAP RPO. Figure 1 is a map depicting the five RPO regions designated by EPA.

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[4] *Regional Haze Rule* (64 FR 35714, July 1, 1999)

Figure 1 Regional Planning Organizations

In SIPs covering the first ten-year period, states were also specifically required to evaluate controls for certain sources that were not in operation prior to 1962, were in existence in 1977, and had the potential to emit 250 tons per year or more of any air pollutant. These sources were referred to as "BART-eligible sources." States were required to make BART determinations for all BART-eligible sources or consider exempting some sources from BART requirements because they did not cause or contribute to visibility impairment in a Class I area. BART-eligible sources that were determined to cause or contribute to visibility impairment in a Class I area were subject to BART controls. In determining BART emissions limitations for each subject-to-BART source, States were required to take into account the existing control technology in place at the source, the cost of compliance, energy and nonair environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that was reasonably anticipated from use of each technology considered. States also had the flexibility to choose an alternative to BART—such as an emissions trading program—that would achieve greater reasonable progress in visibility protection than implementation of source-by-source BART controls. SIPs for the first ten-year planning period were due on December 17, 2007.

In 2005, EPA issued a revised BART rule pursuant to a partial remand of the 1999 RHR by the U.S. Court of Appeals of the DC District Court in 2002.[5] The Court had remanded the BART provisions of the 1999 RHR to EPA and denied industry's challenge to the RHR goals of natural visibility and no degradation. The revised BART rule included guidelines for states to use in determining which facilities must install controls and the type of controls the facilities must use.

[5] American Corn Growers Assn. v. EPA, 291 F.3d.1 (D.C. Cir. 2002)

In addition to revisions to BART, EPA has also issued rulemakings establishing the CAIR and its successor the CSAPR as approvable alternatives to source-by-source BART controls.[6] EPA has also amended regulatory requirements for state regional haze plans for the second planning period and beyond.[7]

On September 9, 2008, Arkansas submitted a SIP for the 2008–2018 planning period to comply with regional haze regulations promulgated as of 2005 codified at 40 C.F.R. Part 51. In a 2012 action on the 2008 AR RH SIP, EPA partially approved and partially disapproved the SIP.[8] This partial approval/partial disapproval of the 2008 AR RH SIP triggered a requirement for EPA to either approve a SIP revision by Arkansas or promulgate a federal implementation plan (FIP) within twenty-four months of the final rule partially approving and partially disapproving the 2008 AR RH SIP.

In the 2012 partial approval/partial disapproval of the 2008 AR RH SIP, EPA approved the following elements of the 2008 AR RH SIP:

- Identification of Class I areas affected by sources in Arkansas;
- Determination of baseline and natural visibility conditions;
- Determination of a uniform rate of progress (URP);
- Select BART determinations:
    - PM determination on SWEPCO Flint Creek Plant Boiler No. 1;
    - SO_2 and PM determinations for the natural gas firing scenario for Entergy Lake Catherine Plant Unit 4;
    - PM determinations for both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Plant Units 1 and 2; and
    - PM determination for Domtar Ashdown Mill Power Boiler No. 1;
- Consultation with FLMs and other states regarding RPGs and long-term strategy;
- Coordination of regional haze and reasonably attributable visibility impairment (RAVI);
- Regional haze monitoring strategy and other SIP requirements under 40 C.F.R. 51.308(d)(4);
- A commitment to submit periodic regional haze SIP revisions; and
- A commitment to submit periodic progress reports that include a description of progress toward RPG and a determination of adequacy of the existing SIP.

EPA disapproved the following elements of the 2008 AR RH SIP:

- BART compliance dates;
- BART-eligible sources and subject-to-BART sources;

[6] Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations (71, FR 60612, October 13, 2006)
Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans (77 FR 33642, June 7, 2012).
[7] Protection of Visibility: Amendments to Requirements for State Plans (82 FR 3078, January 10, 2017)
[8] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

- Select BART determinations:
  - SO_2, NOx, and PM BART determinations for AECC Bailey Plant Unit 1;
  - SO_2, NOx, and PM BART determinations for AECC McClellan Plant Unit 1;
  - SO_2 and NOx BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
  - SO_2, NOx, and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;
  - SO_2 and NOx BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
  - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
  - SO_2 and NOx BART determinations for Domtar Ashdown Mill Power Boiler No. 1; and
  - SO_2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 2;
- RPGs; and
- Long-term strategy.

On September 27, 2016, EPA finalized a regional haze FIP for Arkansas (AR RH FIP).[9] This FIP established new BART requirements for those sources whose BART determinations in the 2008 AR RH FIP were disapproved. The FIP also required the installation of controls at Entergy Independence Units 1 and 2. Despite the previous disapproval of ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area, EPA reversed its decision and concurred with ADEQ that Georgia Pacific Crossett Mill Boiler 6A and 9A are not subject to BART.

On November 22, 2016, the State of Arkansas filed a Petition for Reconsideration and Administrative Stay of the AR RH FIP. In the petition, the State of Arkansas requested that EPA reconsider the AR RH FIP based on new information not raised during the comment period that was of central relevance to the outcome of the FIP. Arkansas asserted that EPA should reconsider controls on Entergy Independence in light of recent data from the IMPROVE monitoring network that shows that Arkansas has already achieved the amount of progress required for the 2008–2018 planning period without having implemented the controls required in the FIP. Arkansas requested that EPA reconsider NOx emissions limitations placed on BART-eligible facilities in light of the recent rulemaking that increased the stringency of the CSAPR. Arkansas also requested reconsideration of the use of low sulfur coal (LSC) as BART for SO_2 at Entergy White Bluff during the 2008–2018 planning period. Lastly, Arkansas requested an immediate administrative stay pending completion of EPA's reconsideration of the AR RH FIP.

On February 3, 2017, the State of Arkansas filed a Petition for Review of the AR RH FIP with the United States Court of Appeals for the Eighth Circuit. On March 8, 2017, the Court held the

[9] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule (81 FR 66332, September 27, 2016)

case in abeyance for ninety days. On April 14, 2017, EPA issued a letter notifying Arkansas that the Agency was convening the reconsideration process for the following:

- Compliance dates for NOx emissions limitations for Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2;
- Low-load NOx limitations applicable to White Bluff Units 1 and 2 and Independence Units 1 and 2 during periods of operation at less than fifty percent of the unit's maximum heat input rating;
- SO_2 emissions limitations for White Bluff Units 1 and 2; and
- Compliance dates for SO_2 emissions limitations for Independence Units 1 and 2.

On April 25, 2017, EPA published in the Federal Register a partial stay of the effectiveness of the AR RH FIP (82 FR 18994). Specifically, EPA stayed from April 25, 2017 until July 24, 2017 (ninety days) the compliance dates for the NOx emissions limitations at AECC Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, as well as the compliance dates for the SO_2 emissions limitations for White Bluff units 1 and 2 and Independence Units 1 and 2. This action did not alter or extend the ultimate compliance dates for these units nor did it stay requirements for other units subject to the FIP.

On July 8, 2017, ADEQ proposed revisions to the State's Regional Haze SIP specifically to address NOx from electric generating units (NOx Regional Haze SIP). The NOx Regional Haze SIP revision sought to replace source-specific NOx BART determinations included in the 2008 AR RH SIP, as well as the NOx limitations promulgated under the AR RH FIP, with reliance on the CSAPR trading program. The NOx Regional Haze SIP revision proposal demonstrates that Arkansas meets all of the current requirements under 40 C.F.R. § 51.308(e)(4) for an alternative to NOx BART. ADEQ submitted the proposed NOx Regional Haze SIP to EPA Region 6 on July 12, 2017 and requested parallel processing. EPA proposed approval of the NOx Regional Haze SIP on September 11, 2017.[10]

On July 13, 2017, EPA proposed revisions to the AR RH FIP that would extend the compliance dates for the NOx emissions limitations at AECC Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2.[11] In the proposal, EPA stated that the Petition for Reconsideration submitted by the State of Arkansas on November 22, 2016, as well as the petitions submitted by the owners of the five units, raised certain arguments regarding the feasibility of eighteen-month NOx compliance dates for the five units that have merit and warrant proposal of a revision to the AR RH FIP with respect to those compliance dates. Therefore, EPA proposed extension of the NOx compliance dates by twenty-one months.

On July 31, 2017, the Eighth Circuit Court of Appeals granted a motion by the parties to hold the case in which the EPA's FIP is at issue in abeyance until September 26, 2017. On October 2, 2017, the Court subsequently issued an order that continued the abeyance until October 31, 2017, as requested by the parties' joint status report.

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[10] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan (82 FR 42627, September 11, 2017)

[11] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Revision of Federal Implementation Plan (82 FR 32284, July 13, 2017)

III. Revisions to BART-Eligible and Subject-to-BART Sources

EPA disapproved the list of BART-eligible and subject-to-BART sources included in the 2008 AR RH SIP. The 2008 AR RH SIP inadvertently omitted Georgia Pacific Crossett Mill Boiler 6A and 9A from the list of BART-eligible sources in Table 9.1 on page 45; however, Georgia Pacific Crossett Mill 6A and 9A were included in the list of BART-eligible sources adopted into APC&EC Regulation No. 19 and submitted with the 2008 AR RH SIP.

Table 1 below is a correction to the list of BART-eligible units in Arkansas in the SIP.

Table 1 Facilities with BART-Eligible Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMbtu)/hour – Electric Generating Units (EGUs)	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine Plant	30-00011	SN-03	Unit 4 Boiler
	Entergy Ritchie	54-00017	SN-02	Unit 2
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek Power Plant	04-00107	SN-01	Boiler
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03	#1 Power Boiler
			SN-05	#2 Power Boiler

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
	Delta Natural Kraft and Mid America Packaging, LLC.	35-00017	SN-02	Recovery Boiler
	Evergreen Packaging Inc., Pine Bluff Mill	35-00016	SN-04	#4 Recovery Boiler
	Georgia-Pacific Corporation Crossett Paper Operations	02-00013	SN-19 SN-22	6A Boiler 9A Boiler
	Green Bay Packaging, Inc. Arkansas Kraft Division	15-00001	SN-05A	Recovery Boiler
	Potlatch Forest Products Corporation – Cypress Bend Mill	21-00036	SN-04	Power Boiler
11. Petroleum Refineries	Lion Oil Company	70-00016	SN-809	#7 Catalyst Regenerator
15. Sulfur Recovery Plant	Albemarle Corporation South Plant	14-00028	SR-01	Tail Gas Incinerator
19. Sintering Plants	Big River Industries	18-00082	SN-01	Kiln A
21. Chemical Processing Plants	Albemarle Corporation South Plant	14-00028	BH-01 BH-02	Boiler #1 Boiler #2
	FutureFuel Chemical Co.	32-00036	6M01-01	3 Coal Boilers
	El Dorado Chemical Company	70-00040	SN-08	West Nitric Acid Plant

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
			SN-09	East Nitric Acid Plant
			SN-10	Nitric Acid Concentrator

Although EPA initially disapproved ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific-Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area and were not subject to BART, EPA reversed its decision in the 2016 AR RH FIP and concurred with ADEQ that Georgia-Pacific Crossett Mill Boiler 6A and 9A are not subject to BART. This reversal was supported by information provided by Georgia-Pacific regarding revisions to emission limits included in their Title V permit and additional dispersion modeling conducted using those revised limits.[12] The results of this modeling demonstrated that the maximum impact of Georgia-Pacific Crossett's boilers on any Class I area was less than the 0.5 dv threshold used by ADEQ to determine whether a BART-eligible source should be considered subject-to-BART. Georgia-Pacific provided further information regarding fuel usage during the 2001–2003 baseline and performed calculations using AP-42, Compilation of Air Pollutant Emission Factors, that demonstrated that emission rates during the 2001–2003 baseline were lower than the rates modeled in Georgia Pacific's 2011 BART screening modeling and lower than their currently enforceable Title V permit limits.[13][14] Therefore, EPA concluded that, based upon the additional information provided by Georgia-Pacific, Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART. ADEQ concurs that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART; therefore, no revisions are necessary to the list of subject-to-BART sources in Arkansas included in the 2008 AR RH SIP. Documentation in support of the determination that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART can be found in Appendix A. Table 2 lists the subject-to-BART sources in Arkansas.

[12] May 18, 2012 letter from Georgia Pacific Crossett Paper Operations to ADEQ. A copy of this letter is included in Appendix A of this SIP.
[13] April 1, 2013 letter from Georgia-Pacific-Crossett to ADEQ and associated supporting attachments.
[14] ADEQ Operating Permit 0597-AOP-R-18

Table 2 Facilities with Subject-to-BART Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMBtu)/hour – Electric Generating Units (EGUs)	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine Plant	30-00011	SN-03	Unit 4 Boiler
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek Power Plant	04-00107	SN-01	Boiler
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03	#1 Power Boiler
			SN-05	#2 Power Boiler

IV. Revisions to BART Determinations

Among the provisions disapproved in EPA's 2012 action on the 2008 AR RH SIP, were several BART determinations. Specifically, EPA disapproved the:

- SO_2, NOx, and PM BART determinations for AECC Bailey Plant Unit 1;
- SO_2, NOx, and PM BART determinations for AECC McClellan Plant Unit 1;
- SO_2 and NOx BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
- SO_2, NOx, and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;

- SO_2 and NOx BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
- BART determination for Entergy White Bluff Plant Auxiliary Boiler;
- SO_2 and NOx BART determinations for Domtar Ashdown Mill Power Boiler No. 1; and
- SO_2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 2.

EPA did approve the following BART determinations:

- PM determination on SWEPCO Flint Creek Plant Boiler No. 1;
- SO_2 and PM determinations for the natural gas firing scenario for Entergy Lake Catherine Plant Unit 4;
- PM determinations for both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Plant Units 1 and 2; and
- PM determination for Domtar Ashdown Mill Power Boiler No. 1.

In this SIP revision, ADEQ is addressing disapproved emissions limitations and compliance schedules for AECC Bailey Unit 1; AECC McClellan Plant Unit 1; SWEPCO Flint Creek Plant Boiler No. 1; Entergy Lake Catherine Plant Unit 4; and Entergy White Bluff Units 1 and 2 and Auxiliary Boiler. All emissions limitations, including those previously approved SIP provisions in Regulation No. 19 Chapter 15, will be rendered enforceable through AOs with each subject-to-BART source. ADEQ requests that EPA withdraw previously SIP-approved BART determinations contained in APC&EC Regulation No. 19 Chapter 15 and approve these AOs into the SIP.

The statutory five factors established in U.S.C. § 7491(g)(2) were analyzed for each subject-to-BART unit. These analyses and the emissions limitations determined thereupon are summarized in Sections IV.A–D of this SIP. The analyses are provided in Appendices B–E. Pursuant to Ark. Code Ann. § 8-4-317, ADEQ also considered the factors set forth in Ark. Code Ann. § 8-4-312 for emissions limitations included in this SIP revision to satisfy BART requirements. The emissions limitations included in this SIP are based upon generally accepted scientific knowledge and engineering practices. The need for each measure in attaining or maintaining the national ambient air quality standards is not applicable to the regional haze program. Table 3 describes how each factor set forth in Ark. Code Ann. § 8-4-312 was considered.

Table 3 Consideration of Ark. Code Ann. § 8-4-312 for BART Limitations

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
(1) The quantity and characteristics of air contaminants and the duration of their presence in the atmosphere that may cause air pollution in a particular area of the state;	These characteristics were considered in modeling conducted for each source's BART analysis.
(2) Existing physical conditions and topography;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(3) Prevailing wind directions and velocities;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
(4) Temperatures and temperature-inversion periods, humidity, and other atmospheric conditions;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(5) Possible chemical reactions between air contaminants or between such air contaminants and air gases, moisture, or sunlight;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(6) The predominant character of development of the area of the state such as residential, highly developed industrial, commercial, or other characteristics	The predominant character of development of the area of the state impacted by this SIP includes Class I areas—specifically Upper Buffalo and Caney Creek. The Class I areas are protected and remain deliberately undeveloped. Furthermore enhanced visibility in these areas will benefit the primary driver of development around Class I areas: tourism.
(7) Availability of air-cleaning devices;	Availability of air cleaning devices was considered as part of each BART analysis.
(8) Economic feasibility of air-cleaning devices	Economic feasibility of air cleaning devices was considered as part of each BART analysis.
(9) Effect on normal human health of particular air contaminants	This factor is not applicable to the regional haze program, which targets visibility improvements.
(10) Effect on efficiency of industrial operation resulting from use of air-cleaning devices;	Effect on efficiency of air cleaning devices was considered as part of each BART analysis.
(11) The extent of danger to property in the area reasonably to be expected from any particular air contaminant;	This factor is not applicable to the regional haze program, which targets visibility improvements.
(12) Interference with reasonable enjoyment of life by persons in the area and conduct of established enterprises that can reasonably be expected from air contaminants;	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP. Costs of control may be passed on to customers of the sources for which ADEQ is establishing emissions limitations; however, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(13) The volume of air contaminants emitted from a particular class of air contamination sources;	The volume of air contaminants emitted from subject-to-BART sources for which controls are included in this SIP are factored into the BART analysis.
(14) The economic and industrial development of the state and the social and economic value	Costs of control may be passed on to customers of the sources for which ADEQ is

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
of the air contamination sources;	establishing emissions limitations. This may have a negative impact on economic and industrial development in the State. However, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(15) The maintenance of public enjoyment of the state's natural resources; and	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP.
(16) Other factors that the department or the commission may find applicable.	Other factors considered by the Department in setting BART controls for subject-to-BART sources are contained in the Sections IV.A–D and Appendices B–E of this SIP.

A. Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the Carl E. Bailey Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is provided in Appendix B of this SIP and summarized below.

AECC Bailey Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1966. Unit 1 has a maximum heat input of 1,350 million British thermal units per hour (MMBtu/hr). AECC Bailey Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC Bailey Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC Bailey Plant Unit 1 contributes greater than 0.5 dv to visibility impairment in at least one Class I area. Although, more recent modeling conducted by Trinity Consultants (Trinity) shows impacts for AECC Bailey Unit 1 that are less than 0.5 dv, AECC conducted a complete BART analysis and identified the AECC Bailey Plant Unit 1 source as the sole AECC Bailey source subject to BART. Consequently, the five BART statutory factors were considered for AECC Bailey Unit 1.

1. Summary of BART Analysis for SO_2

The available control options for AECC Bailey Plant Unit 1 when burning fuel oil are flue gas desulfurization (FGD) systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC Bailey since 2006 had an average sulfur content of 1.81% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC Bailey Plant Unit 1 would result in up to a forty-five percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a seventy-two percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-seven percent control efficiency.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $1,198/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $2,559/ton. The cost-effectiveness of switching to diesel is $5,382/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of Bailey Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require any significant capital costs.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 41.52% reduction in visibility impairment from AECC Bailey at Caney Creek, a 44.25% reduction at Upper Buffalo, a 44.02% reduction at Hercules Glades Wilderness Area (Hercules Glades), and a 45.65% reduction at Mingo Wilderness Area (Mingo). Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 56.97% reduction in visibility impairment from AECC Bailey at Caney Creek, a 63.51% reduction at Upper Buffalo, a 63.32% reduction at Hercules Glades, and a 55.15% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC determined that SO_2 BART for AECC Bailey Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at Bailey Plant Unit 1.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis for PM

Available PM retrofit control technologies include: dry electrostatic precipitator (Dry ESP), wet electrostatic precipitator (Wet ESP), fabric filter, wet scrubber, a cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness values of all evaluated options exceed $22,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC Bailey Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-8 at page 7-9 of AECC's BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-13 at page 5-12. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC Bailey Unit 1. In addition, the BART determination for SO2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will also result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at Bailey Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil.

B. Arkansas Electric Cooperative Corporation John L. McClellan Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the John L. McClellan Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is provided in Appendix B of this SIP and summarized below.

AECC McClellan Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1971. AECC McClellan Plant Unit 1 has a maximum heat input of 1,436 MMBtu/hr. AECC McClellan Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC McClellan Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC McClellan Plant Unit 1 contributes greater than 0.5 dv to visibility impairment in at least one Class I area. Therefore, AECC conducted a complete BART analysis and identified the AECC McClellan Plant Unit 1 source as the sole AECC McClellan source subject to BART. Consequently, the five BART statutory factors were considered for AECC McClellan Unit 1.

1. Summary of BART Analysis for SO_2

The available control options for AECC McClellan Unit 1 when burning fuel oil are FGD systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC McClellan since 2009 had an average sulfur content of 1.38% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC McClellan Plant Unit 1 would result in up to a twenty-eight percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a sixty-four percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-six percent control efficiency.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $2,457/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $4,553/ton. The cost-effectiveness of switching to diesel is $10,698/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of McClellan Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require capital investments in new equipment.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 13.67% reduction in visibility impairment from AECC McClellan at Caney Creek, a 13.16% reduction at Upper Buffalo, a 12.55% reduction at Hercules Glades, and a 15.35% reduction at Mingo. Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 48.23% reduction in visibility impairment from AECC McClellan at Caney Creek, a 45.11% reduction at Upper Buffalo, a 50.22% reduction at Hercules Glades, and a 40.35% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC determined that SO_2 BART for AECC McClellan Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at McClellan Plant Unit 1.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis for PM

Available PM retrofit control technologies include: Dry ESP, Wet ESP, fabric filters, wet scrubber, a Cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness of all evaluated options exceeds $14,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC McClellan Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-9 at page 7-10 of AECC BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-14 at page 5-13. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC McClellan Unit 1. In addition, the BART determination for SO_2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at McClellan Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil.

C. Entergy Arkansas, Inc. Lake Catherine Plant

Entergy provided a BART analysis (dated June 2013) for burning of natural gas at the Entergy Lake Catherine Generating Station. EPA used this analysis in the construction of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by Entergy. This analysis is provided in Appendix C of this SIP and summarized below.

Entergy Lake Catherine Plant Unit 4 is a 558 megawatt tangentially-fired boiler installed in 1970. Entergy Lake Catherine Plant Unit 4 has a maximum heat input of 5,850 MMBtu/hr. Entergy Lake Catherine Plant Unit 4 burns pipeline quality natural gas and is capable of burning No. 6 fuel oil as a secondary fuel, although Entergy has committed to not burning fuel oil at this unit. Therefore, emissions from fuel oil were not considered in the BART analysis and the Entergy Lake Catherine Plant Unit 4 must not burn fuel oil until BART determinations are promulgated for this unit for SO_2, NO_X, and PM for the fuel oil firing scenario through EPA action upon and approval of revised BART determinations submitted by the State as a SIP revision. Entergy Lake Catherine Plant Unit 4 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the Entergy Lake Catherine Plant Unit 4 contributes an existing visibility impairment of greater than 0.5 dv in at least one Class I area. Therefore, Entergy conducted a complete BART analysis and identified the Entergy Lake Catherine Plant Unit 4 source as the sole Entergy Lake Catherine unit subject to BART. Consequently, the five BART statutory factors were considered for Entergy Lake Catherine Plant Unit 4.

1. BART Requirements for SO_2

A BART determination for SO_2 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no SO_2 controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved SO_2 BART limitations included in APC&EC Regulation No. 19 because this limitation has been rendered enforceable through an AO included with this SIP revision.

2. BART Requirements for PM

A BART determination for PM at Lake Catherine Plant Unit 4 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no PM controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved PM BART limitation included in APC&EC Regulation No. 19 because the limitation has been rendered enforceable through an AO included with this SIP revision.

D. Entergy Arkansas, Inc. White Bluff

At the request of ADEQ, Entergy provided an updated BART five-factor analysis for SO_2 for White Bluff (dated August 18, 2017) to supplement previous BART analyses (dated February 2013, October 2013, August 2015, and August 2016) submitted to EPA for their consideration in development of the AR RH FIP. This updated analysis provides new information in light of an updated remaining useful life for White Bluff and evaluates three new control scenarios. Entergy also provided to ADEQ supplemental information on April 5, 2017 detailing cost-effectiveness for Dry FGD with various remaining useful life assumptions. ADEQ makes its BART determination included in this SIP based on the updated BART five-factor analysis for SO_2 and previous BART analyses and supplemental information provided by Entergy, and analyses from other stakeholders of interest. These analyses are incorporated by reference and provided in Appendix D of this SIP.

Entergy White Bluff Units 1 and 2 are identical tangentially-fired 850 megawatt boilers, which were installed in 1974, and they have a maximum heat input capacity of 8,950 MMBtu/hr each. These units are currently equipped with ESPs to control PM emissions. Entergy White Bluff Units 1 and 2 burn sub-bituminous coal as a primary fuel and burn No. 2 fuel oil or biofuel as a start-up fuel. Entergy White Bluff also has a rarely used 183 MMBtu/hr auxiliary boiler that burns only No. 2 fuel oil or biodiesel. Entergy White Bluff Units 1 and 2 and the auxiliary boiler meet the BART eligibility criteria. Because modeling demonstrates that the auxiliary boiler's greatest impact on visibility at any Class 1 area is only 0.01 dv, EPA determined that existing emissions limitations for the auxiliary boiler in Entergy's permit satisfy BART for SO_2, NOx, and PM. ADEQ concurs with this determination. Entergy White Bluff Units 1 and 2 contribute greater than 0.5 dv to at least one Class I area. Consequently, the five BART statutory factors were considered for Entergy White Bluff Units 1 and 2.

1. Summary of BART Analyses for SO_2

The available SO_2 retrofit control technology options for White Bluff Units 1 and 2 include: fuel switching to lower sulfur coal, dry sorbent injection (DSI), spray dryer absorber (SDA), circulating dry scrubber (CDS), and Wet FGD. All evaluated options were considered technically feasible.

Fuel switching to coal with a sulfur content of 0.6 lb/MMBtu would result in an 8.75% reduction in SO_2 emissions from baseline levels.

DSI, which is the injection of sorbent into the exhaust gas stream, has a control efficiency that can range from forty to ninety percent based on sorbent particle size, residence time, temperature, and particulate collection equipment. Entergy evaluated two particulate collection methods for DSI at Entergy White Bluff. The first collection method would require retrofits to the currently installed ESP and would achieve a fifty percent SO_2 removal efficiency. The second "enhanced" collection method would require the installation of a baghouse and would achieve an eighty percent SO_2 removal efficiency. Both evaluated DSI technologies would require landfilling of DSI waste.

SDA and CDS, both Dry FGD systems, have control efficiencies ranging from sixty to ninety-five percent. Both systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter.

Wet FGD, scrubbing the exhaust gas stream with a lime or limestone slurry, is capable of achieving eighty to ninety-five percent control of SO_2 emissions. This option was eliminated in previous analyses and in the AR RH FIP due to the small incremental difference in visibility improvement between Wet FGD and Dry FGD relative to the marginal cost difference.

a. Existing Controls in Use at the Source

The current permitted emissions rate for Units 1 and 2 at Entergy White Bluff is 1.2 lb SO_2/MMBtu based on the new source performance standard for fossil-fuel fired steam generators. Entergy White Bluff is currently using lower sulfur content coal to minimize costs of compliance with the Acid Rain Program. Entergy White Bluff has been able to achieve monthly average emissions rates below 0.69 SO_2/MMBtu.[15] The average monthly emissions rate between 2014 and 2016 was 0.55 lb SO_2/MMBTU for Unit 1 and 0.58 lb SO_2/MMbtu for Unit 2. Consequently, Entergy White Bluff has already lowered its visibility impact on potentially impacted federal Class I areas during this planning period beyond what would be expected due to emissions at its permitted emissions rate.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. For some technologies, remaining useful life is a significant factor in determining annual cost. The cost of fuel switching to LSC is not dependent on the remaining useful life of White Bluff Units 1 and 2 or equipment because no capital investments in equipment are required. The other evaluated control technologies require capital investments in new equipment or retrofit of existing equipment. These capital investments are amortized over the remaining useful life of White Bluff Units 1 and 2 to determine the annual cost-effectiveness of SO_2 emissions reductions. The remaining useful life assumptions are discussed in section IV(D)(1)(d) below.

[15] Calculated using 2014–2016 monthly SO_2 emissions and heat rate (MMBtu) obtained from the Air Markets Program Database https://ampd.epa.gov/ampd/

Switching to LSC entails an increased annual cost of operation based on purchase contract terms for the specific sulfur content of the coal. Entergy estimates an increase in operation and maintenance costs based on a \$0.50 per ton cost premium to guarantee that the sulfur content of coals is less than 0.6 lb/MMBtu. Thus, the cost-effectiveness for LSC is approximately \$1,150 per ton of SO_2 reduced.

In Entergy's August 18, 2017 revised BART analysis, Entergy redacted certain information held to be a trade secret, including capital costs, remaining useful life, and average cost-effectiveness for DSI, Enhanced DSI, and Dry FGD. They did provide baseline and controlled emission rates, annual cost-effectiveness for LSC, and incremental cost-effectiveness values of control technologies versus LSC without redaction. Using these data provided without redaction by Entergy, ADEQ was able to calculate the average cost-effectiveness of each technology. The average cost-effectiveness of DSI is approximately \$6,239 per ton and the average cost-effectiveness of "enhanced" DSI is approximately \$6,405 per ton. Average cost-effectiveness of Dry FGD systems is approximately \$5,403 per ton. Cost-effectiveness of Wet FGD was not calculated in the updated five factor analysis because EPA already determined in the AR RH FIP that Wet FGD is not BART because Wet FGD is more expensive than Dry FGD technologies with a 0.028 dv or less incremental impact at Class I areas. The incremental cost of Wet FGD would be even greater considering the updated remaining useful life for Entergy White Bluff Units 1 and 2.

The cost-effectiveness estimates for all control options evaluated, with the exception of LSC, are greater than what is typically considered cost-effective. Based on these cost-effectiveness estimates, ADEQ concludes that DSI, Dry FGD, and Wet FGD are not BART. Each of the add-on control options DSI and Dry FGD also have a high dollar-per-deciview cost. Average dollar-per-deciview cost for LSC, DSI and Dry FGD are included in Table 4.

Table 4 Average Dollar-Per-Deciview Reduction for Control Options at White Bluff Units 1 and 2[16]

Control Option	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	\$14,500,519	\$11,932,988	\$10,666,332	\$13,554,882
DSI	\$133,339,191	\$105,415,609	\$120,510,530	\$116,123,315
Enhanced DSI	\$158,836,782	\$139,148,713	\$168,877,211	\$173,411,916
SDA	\$131,451,261	\$121,376,462	\$153,169,879	\$153,856,146

c. Energy and Nonair Quality Environmental Impacts

Entergy indicated that there were energy and adverse nonair quality environmental impacts associated with add-on controls under consideration, such as DSI and Dry FGD. These impacts were factored into costs of compliance.

[16] Total annualized cost, as calculated by ADEQ using information from Entergy's August 18, 2017 revised BART analysis for White Bluff regarding annualized cost for LSC and the incremental cost-effectiveness of the other control options over LSC, divided by visibility improvements that would be anticipated from evaluated technologies included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8.

d. Remaining Useful Life

In the August 18, 2017 updated BART analysis for White Bluff, Entergy amortized costs based on their proposal regarding changes in coal-fired operations. The August 18, 2017 analysis redacted Entergy's proposed date to enact these changes; however, the cost-effectiveness for Dry FGD included in the August 18, 2017 analysis corresponds to Dry FGD cost-effectiveness estimates provided in Entergy's April 21, 2017 letter based on a seven-year to eight-year remaining useful life scenario.[17] In comments on the AR RH FIP, Entergy also proposed dates as part of a "multi-unit plan to improve visibility and to better manage generation assets for reliability and costs."[18] In those comments, Entergy proposed to "take an enforceable limit" regarding their planned changes in coal-fired operations.[19]

Under the guidelines for BART determinations, the remaining useful life calculation should begin on "the date that controls will be put in place" (compliance date) and ending on "the date the facility permanently stops operations."[20] Based on the controls evaluated, the compliance date for controls would be as expeditiously as practicable, but in no event later than five years after approval of the SIP.[21] The guidelines further specify that the permanent operations cessation date should be "assured by a federally- or State-enforceable restriction preventing further operation."[22] Therefore, ADEQ agrees that Entergy's cost-effectiveness calculations are reasonable based on a remaining useful life of seven years and Entergy's proposal to take an enforceable limit regarding the timing of their planned changes in coal-fired operations date.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8. Based on remaining useful life, DSI, Dry FGD, and Wet FGD were eliminated as BART for SO_2. The remaining evaluated option, switching to LSC, would result in a 0.129 dv improvement at Caney Creek and a 0.143 dv improvement at Upper Buffalo.

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[17] In the April 21, 2017 letter included in Appendix D, Entergy estimates that "for a seven- to eight-year [remaining useful life], the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $6,500–$7,200 based on the full costs and $5,000-$5,500 based on partial costs."

[18] Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "EAI Comments").

[19] Id.

[20] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)

[21] 40 CFR 51.308(e)(iv) requires that "each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than five years after approval of the implementation plan revision." Appendix Y to Part 51, Guidelines for BART Determinations Under the Regional Haze Rule V. Enforceable Limits/Compliance Date also specifies that in developing a compliance date for BART, a "you must require compliance with the BART emission limitations no later than 5 years after EPA approves your regional haze SIP." Therefore beginning calculation of remaining useful life based on a compliance date five years after approval of the SIP is consistent with the requirements of the Regional Haze Rule.

[22] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)

f. BART Requirements for SO_2

Based on their analysis, Entergy proposed that BART to control SO_2 emissions from Entergy White Bluff Units 1 and 2 was LSC with a required emissions rate of 0.6 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day. ADEQ concurs with this determination. In communication with ADEQ, Entergy indicated that it is their practice to project how much coal will be needed in future years and to contract for a portion of their coal supply up to three years in advance. Furthermore, Entergy keeps a reserve supply of coals at White Bluff to ensure that the units can operate in the event of a fuel supply disruption. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.6 lb/MMBtu at Entergy White Bluff Unit 1 and Unit 2 no later than three years after approval of this SIP revision.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's determination.

2. BART Requirements for PM

A BART determination for PM for Entergy White Bluff Units 1 and 2 was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). No changes are needed to EPA's determinations with respect to previously approved PM BART limitations (0.10 lb/MMBtu) included in APC&EC Regulation No. 19 because these limitations have been rendered enforceable through an AO included with this SIP revision.

E. Southwest Electric Power Company Flint Creek Power Plant

SWEPCO, a subsidiary of AEP, provided a BART analysis (dated September 2013, Version 4) for the Flint Creek Power Plant. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by SWEPCO. This analysis is provided in Appendix E of this SIP and summarized below.

SWEPCO Flint Creek Plant Boiler No. 1 is a 558 megawatt dry bottom wall-fired boiler that commenced operation in 1978. SWEPCO Flint Creek Plant Boiler No. 1 has a maximum heat input of 6,324 MMBtu/hr. SWEPCO Flint Creek Plant Boiler No. 1 is equipped with Dry FGD with a Pulse Jet Fabric Filter (PJFF) and Activated Carbon Injection (ACI). SWEPCO Flint Creek Plant Boiler No. 1 burns low sulfur western coal as a primary fuel, but can also combust fuel oil and tire-derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, during startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, for No. 2 fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and during malfunction. SWEPCO Flint Creek Plant Boiler No. 1 meets the BART-eligibility criteria. Also, based on results of air dispersion modeling, the SWEPCO Flint Creek Plant Boiler No. 1 contributes greater than 0.5 dv to visibility impairment in at least one Class I area. Consequently, the five BART statutory factors were considered for SWEPCO Flint Creek Plant Boiler No. 1.

1. Summary of BART Analysis for SO_2

The available SO_2 retrofit control technology options include DSI, Dry FGD, and Wet FGD. DSI, a form of FGD, has a control efficiency of forty to sixty percent and was considered technically feasible in SWEPCO's BART analysis for the SWEPCO Flint Creek Plant Boiler No. 1. A Dry FGD was also deemed a technically feasible option and has a control efficiency of sixty to ninety-five. Novel integrated deacidification (NID), a form of Dry FGD, was predicted to have an achievable ninety-two percent control efficiency on the SWEPCO Flint Creek Plant Boiler No. 1. Wet FGD was also considered a technically feasible option and has an eighty to ninety-five percent control efficiency.

a. Existing Controls in Use at the Source

At the time SWEPCO performed a BART analysis, no SO_2 controls were in place at Flint Creek Plant Boiler No. 1. Since that time, SWEPCO has installed an NID system to comply with SO_2 BART requirements included in the AR RH FIP. Cost-effectiveness and visibility improvement data included in SWEPCO's BART analysis are based on the 2001–2003 baseline, not current SO_2 controls in place at Flint Creek Plant Boiler No. 1.

b. Cost of Compliance

SWEPCO determined the cost effectiveness of a Wet FGD at an SO_2 rate of 0.04 lb/MMBtu (ninety-five percent control of baseline emissions) is $4,919/ton of SO_2 removed, while cost effectiveness of a NID system at an SO_2 rate of 0.06 lb/MMBtu (ninety-two percent control of baseline emissions) is $3,845/ton of SO_2 removed. Because technologies with higher control efficiencies were within the range considered cost-effective, the costs of DSI were not evaluated.

c. Energy and Nonair Quality Environmental Impacts

SWEPCO concluded that although Wet FGD was expected to achieve a slightly higher level of SO_2 control compared to NID technology, a negative energy or nonair quality impact associated with Wet FGD was the generation of large volumes of wastewater and solid waste/sludge that must be treated. Also, Wet FGD systems have increased power requirements and increased reagent usage over Dry FGD, as well as the potential for increased particulate and sulfuric acid mist releases.

d. Remaining Useful Life

The remaining useful life of SWEPCO Flint Creek Plant Boiler No. 1 does not impact the annualized capital costs because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated control technologies are included in Table 5-7 on page 5-9 of SWEPCO's 2013 BART analysis. Operation of NID at SWEPCO Flint Creek Plant Boiler No. 1 will result in up to a 0.647 dv improvement to the existing visibility impairment and Wet FGD does not add additional visibility improvement over Dry FGD because Wet FGD results in other visibility impairing emissions.

f. BART Requirements for SO_2

SWEPCO proposed that BART to control SO_2 emissions from SWEPCO Flint Creek Plant Boiler No. 1 was NID technology with an expected emissions rate of 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day. ADEQ concurs with this determination.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. BART Requirements for PM

A BART determination for PM based on the existing ESP controls was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). This determination also approved the existing PM emissions rate of 0.10 lb/MMBtu. ADEQ proposes that no changes are needed to EPA's determination with respect to the previously approved PM BART limit included in Regulation No. 19 because this limitation has been rendered enforceable through an AO included with this SIP revision.

V. <u>Reasonable Progress Analysis for Arkansas Class I Areas</u>

The 1999 RHR requires states to establish RPGs for each Class I area within the state. These goals must ensure reasonable progress consistent with the URP necessary to achieve natural visibility conditions by 2064 on the twenty percent worst days and no degradation on the twenty percent best days. The URP is also referred to as the "glidepath." In establishing RPGs, the RHR requires states to consider four factors: (1) cost of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of potentially affected sources. If a state determines that additional progress beyond what is necessary to achieve the URP is reasonable, the RHR rule states that "the State should adopt that amount of progress as its goal for the first-long-term strategy." The RHR also requires states to provide a demonstration as part of the SIP if the State determines that the URP needed to reach natural conditions is not reasonable. In its 2007 reasonable progress guidance, EPA states that the "glidepath is not a presumptive limit and states may establish an RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath."[23] The guidance also instructs the states in the following manner:

> In deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal.[24]

[23] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[24] Id.

In the 2008 AR RH SIP, ADEQ established a URP for Caney Creek and Upper Buffalo based on the progress needed to reach natural conditions by 2064 in each area. The 2008 AR RH SIP established RPGs based on a combination of mandated controls, including BART requirements, and demonstrated that these measures would provide for a rate of progress that improves visibility conditions on the worst days at a rate that surpasses the URP and would prevent degradation on the best days. ADEQ reasoned that no four factor analysis was required because the State determined that no additional controls were necessary to ensure reasonable progress toward natural visibility by 2064 beyond those controls required for sources subject to BART requirements. Therefore, the 2008 AR RH SIP did not include a four factor analysis.

In 2012, EPA issued a partial approval and a partial disapproval of the 2008 AR RH SIP. In this action, EPA approved the URP, but disapproved the RPGs. In justifying its disapproval of Arkansas's RPGs, EPA asserted that the URP does not establish a "safe harbor" for the State in setting its RPGs and that Arkansas should have performed a four factor analysis and determined whether additional progress would be reasonable.[25] This submittal addresses EPA's disapproval of the reasonable progress analysis included in the 2008 AR RH SIP by considering key pollutants that contribute to visibility impairment in Arkansas Class I areas and using the four factors to assess whether controls on sources that are not subject to BART are reasonable. Technical supporting information for the reasonable progress analysis can be found in Appendix F.

A. Identification of Key Pollutants and Source Categories That Contribute to Visibility Impairment in Arkansas Class I Areas

Included with the 2008 AR RH SIP, ADEQ provided emissions and air quality modeling performed by Central Regional Air Planning Association (CENRAP) in support of SIP development in the central states region.[26] As part of this modeling, the Particulate Source Apportionment Technology Tool (PSAT), included with CAMx Version 4.4, was used to provide source apportionment by geographic regions and major source categories for pollutants that contribute to visibility impairment at each of the Class I areas in the central states region.[27] The PSAT results demonstrate that sulfate (SO_4) from point sources is the principle driver of light extinction at both Arkansas Class I areas on the twenty percent worst days.

1. Regional Particulate Source Apportionment for Caney Creek and Upper Buffalo

Table 5 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty-percent worst days in 2002. Point sources, responsible for approximately sixty percent of total light extinction at each Arkansas Class I area, are the primary contributor to light extinction on the twenty percent worst days. Area sources are the next largest contributor to light extinction at Arkansas Class I areas; however,

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[25] Approval and Promulgation of Implementation Plans; Arkansas Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze: Proposed Rule (76 FR 64186 at 64195, October 17, 2011)

[26] The central states region includes Texas, Oklahoma, Louisiana, Arkansas, Kansas, Missouri, Nebraska, Iowa, Minnesota; and tribal governments included in these states.

[27] August 27, 2007 CENRAP PSAT tool: W20% Projected Bext;

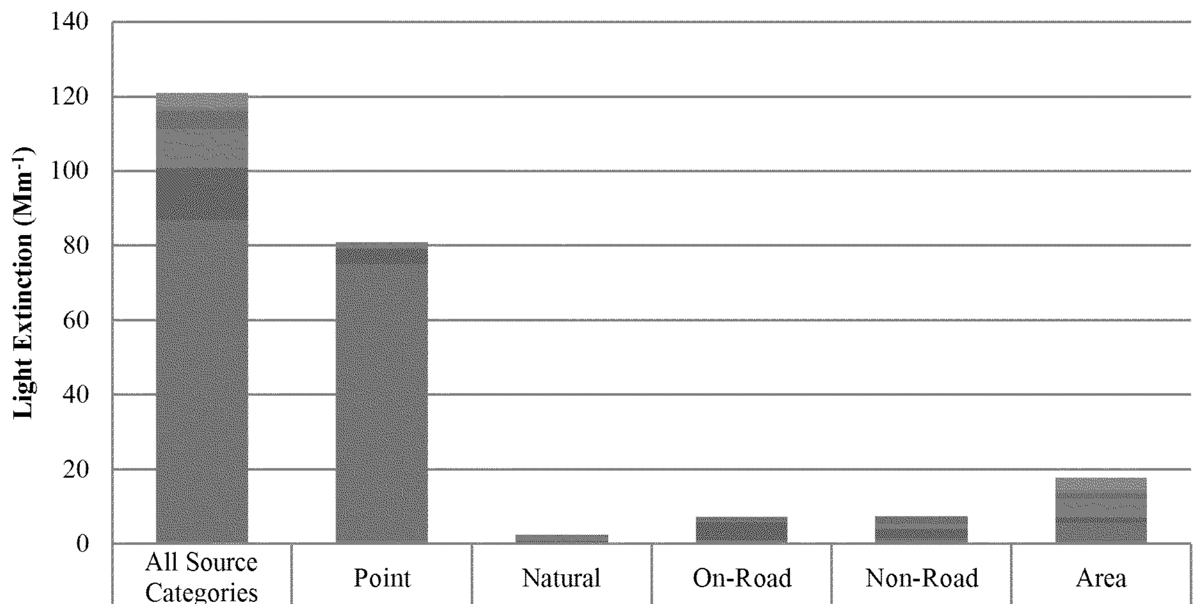
area sources only contribute thirteen percent and sixteen percent of total light extinction at Caney Creek and Upper Buffalo, respectively. The other source categories each contribute between two percent and six percent of total light extinction at Arkansas Class I areas.

Table 5 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	81.04	2.45	7.26	7.31	17.81
Upper Buffalo	77.8	2.39	6.62	7.72	20.46

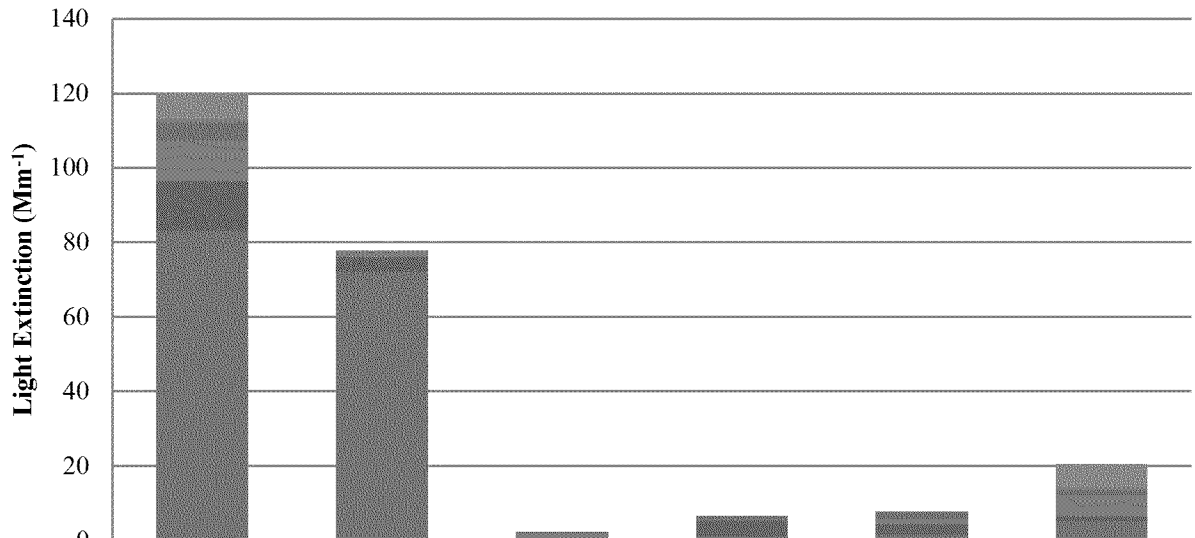
Figure 2 and Figure 3 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. According to the 2002 PSAT results, SO_4 contributed approximately sixty-five percent and sixty-three percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. The point source category contributed eighty-six percent and eighty-seven percent of light extinction due to SO_4 at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. The other source categories contribute much smaller proportions of light extinction due to SO_4. In fact, point sources of SO_4 contributed fifty-five to fifty-six percent of total light extinction at Arkansas Class I areas. By contrast, nitrate (NO_3) contributed approximately ten percent, primary organic aerosols (POA) contributed approximately eight percent, elemental carbon (EC) contributed approximately four percent, and soil contributed approximately one percent of modeled light extinction at both wilderness areas in 2002 on the twenty percent worst days. Crustal material (CM) contributed approximately three percent and five percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. Relative contributions from on-road and point sources each represent approximately a third of light extinction attributed to NO_3. Area sources were the primary driver of light extinction attributed to POA, soil, and CM. Light extinction attributed to EC is primarily driven by non-road and area sources.

Figure 2 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.73	0.21	0.04	0.03	0.02	3.19
SOIL	1.12	0.19	0.01	0.01	0.01	0.87
EC	4.8	0.19	0.33	0.86	1.79	1.4
POA	10.5	1.29	1.33	0.46	1.34	5.32
NO3	13.78	4.06	0.64	4.7	2.45	1.37
SO4	87.05	75.1	0.09	1.19	1.7	5.66

Figure 3 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.85	0.29	0.05	0.05	0.02	6.02
SOIL	1.21	0.2	0.02	0.01	0.01	0.93
EC	4.72	0.16	0.31	0.8	1.93	1.3
POA	10.85	1.06	1.33	0.47	1.38	5.75
NO3	13.3	3.93	0.61	4.14	2.71	1.23
SO4	83.18	72.17	0.08	1.15	1.67	5.24

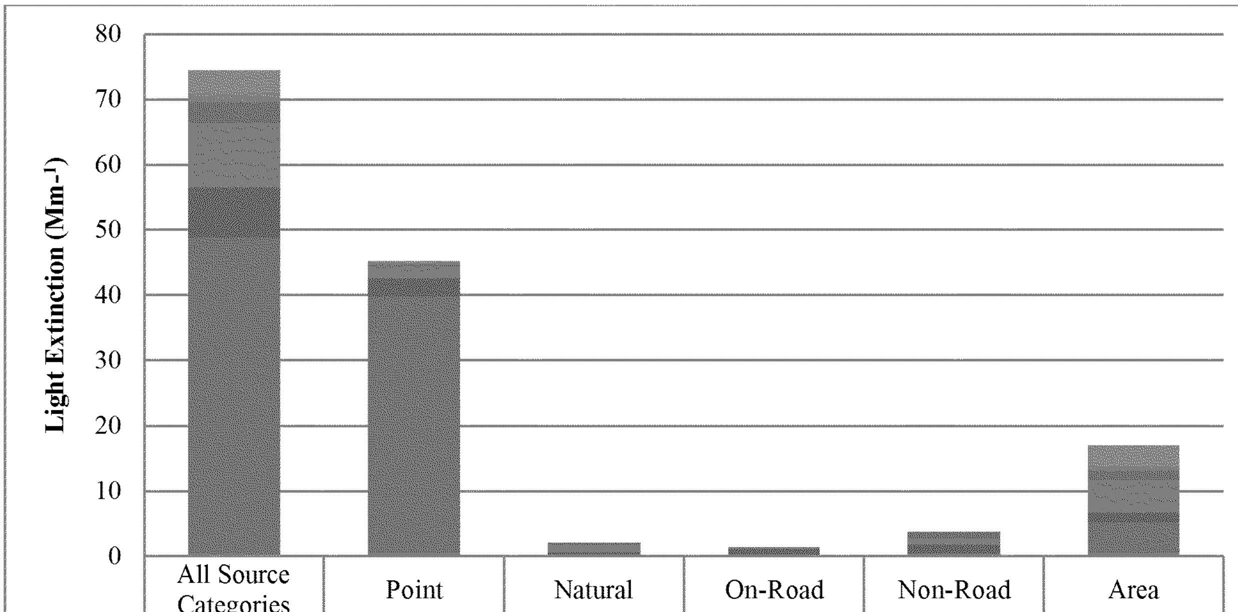
Table 6 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Point sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas. Point sources are projected to contribute approximately fifty-three percent of total light extinction at Caney Creek and fifty percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Area sources are also projected to continue to be the second largest contributor to light extinction with contributions of twenty percent of total light extinction at Caney Creek and twenty-three percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Natural, on-road, and non-road sources are projected to continue to contribute a very small portion of total light extinction at Arkansas Class I areas on the twenty percent worst days in 2018.

Table 6 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	45.27	2.12	1.44	3.76	16.96
Upper Buffalo	43.02	2.24	1.57	4.25	19.71

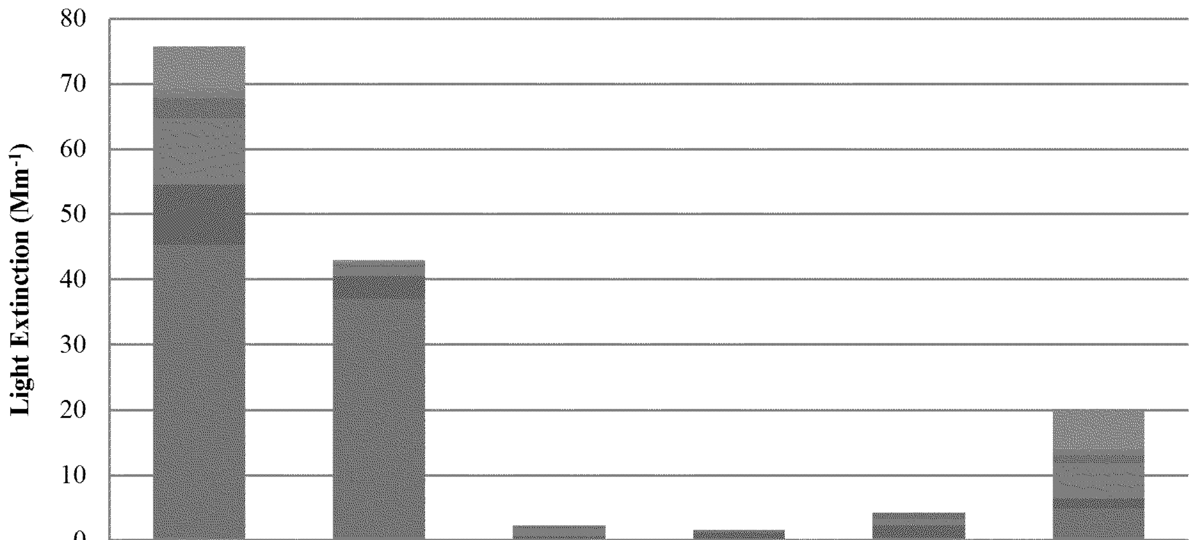
Figure 4 and Figure 5 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2018. According to the regional PSAT data, light extinction attributed to SO_4 is projected to decrease on the twenty percent worst days by forty-four percent at Caney Creek and by forty-five percent at Upper Buffalo between 2002 and 2018; however, SO_4 is projected to continue to be the primary driver of total light extinction. The 2018 projections show that point sources will continue to be the primary source of light extinction due to SO_4. Point sources of SO_4 are projected to contribute forty-three to forty-six percent of total light extinction on the twenty percent worst days in 2018 in Arkansas Class I areas. The other species are also projected to see reductions in their contribution to total light extinction; however, their relative contributions to total light extinction during 2018 remain much smaller than that of SO_4. Light extinction on the twenty percent worst days attributed to NO_3 from on-road sources is projected to decrease more rapidly than light extinction attributed to NO_3 from point sources; however, point sources of NO_3 will only contribute three to four percent of total light extinction at Arkansas Class I areas on the twenty percent worst days based on 2018 projections.

Figure 4 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.58	0.24	0.04	0.03	0.01	3.02
SOIL	1.29	0.35	0.01	0.01	0.01	0.87
EC	3.17	0.24	0.3	0.16	0.94	1.31
POA	9.93	1.76	1.18	0.14	1.03	5.09
NO3	7.57	2.84	0.53	0.97	1.33	1.37
SO4	48.95	39.83	0.07	0.12	0.44	5.31

Figure 5 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.53	0.36	0.05	0.04	0.02	5.65
SOIL	1.4	0.4	0.01	0.01	0.01	0.93
EC	3.07	0.21	0.28	0.15	0.99	1.21
POA	10.17	1.48	1.2	0.14	1.01	5.49
NO3	9.22	3.48	0.63	1.1	1.81	1.48
SO4	45.38	37.09	0.06	0.12	0.42	4.95

2. Arkansas Particulate Source Apportionment for Caney Creek and Upper Buffalo

The relative contribution of sources within Arkansas to total light extinction on the twenty percent worst days at both Arkansas Class I areas is small. Species attributed to Arkansas sources contributed approximately ten percent of total light extinction on the twenty percent worst days in Arkansas Class I areas according to 2002 data and are projected to contribute between thirteen and fourteen percent of total light extinction on the twenty percent worst days in Arkansas Class I areas in 2018. Total light extinction is projected to decrease by thirty-five percent on the twenty percent worst days at Arkansas Class I areas between 2002 and 2018. Light extinction on the twenty percent worst days attributed to species from Arkansas sources is projected to decrease by seventeen percent at Caney Creek and to decrease by eleven percent at Upper Buffalo between 2002 and 2018.

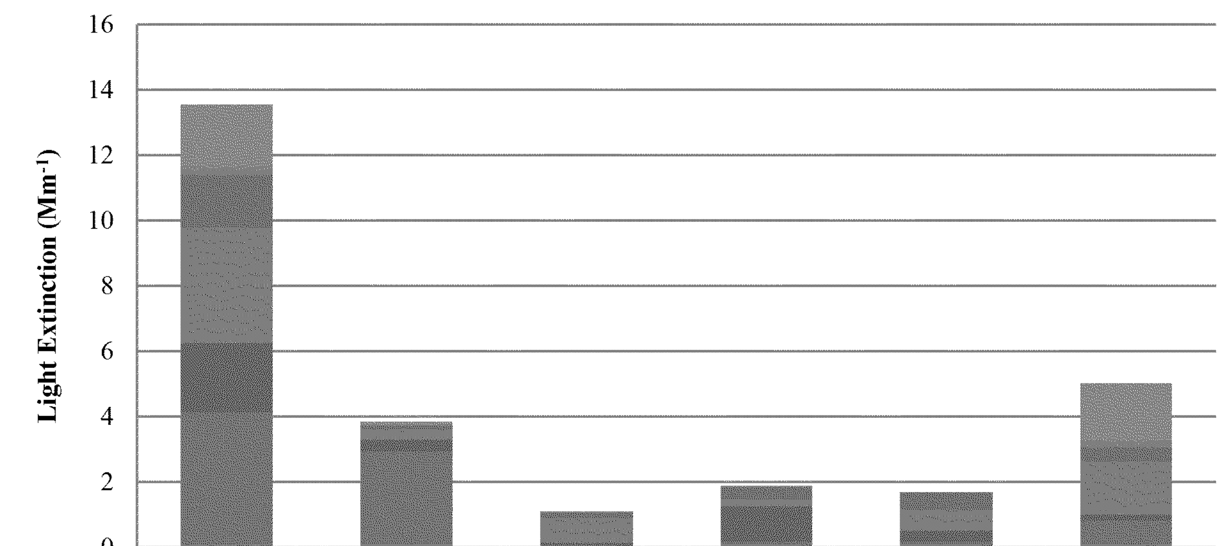
Table 7 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. Area sources had a larger impact on light extinction than did point sources when only sources within Arkansas were considered. On the twenty percent worst days in 2002, area sources contributed approximately thirty-seven percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Caney Creek and fifty percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Upper Buffalo. Point sources contributed approximately twenty-eight percent of light extinction attributed to Arkansas sources (three percent of total light extinction) at Caney Creek and twenty-four percent of light extinction attributed to Arkansas sources (two percent of total light extinction) at Upper Buffalo on the twenty percent worst days. The other sources in Arkansas contributed between seven and fourteen percent each to light extinction attributed to Arkansas sources (approximately one percent each to total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2002.

Table 7 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	3.85	1.1	1.88	1.72	5.03
Upper Buffalo	3.25	0.94	1.29	1.26	6.72

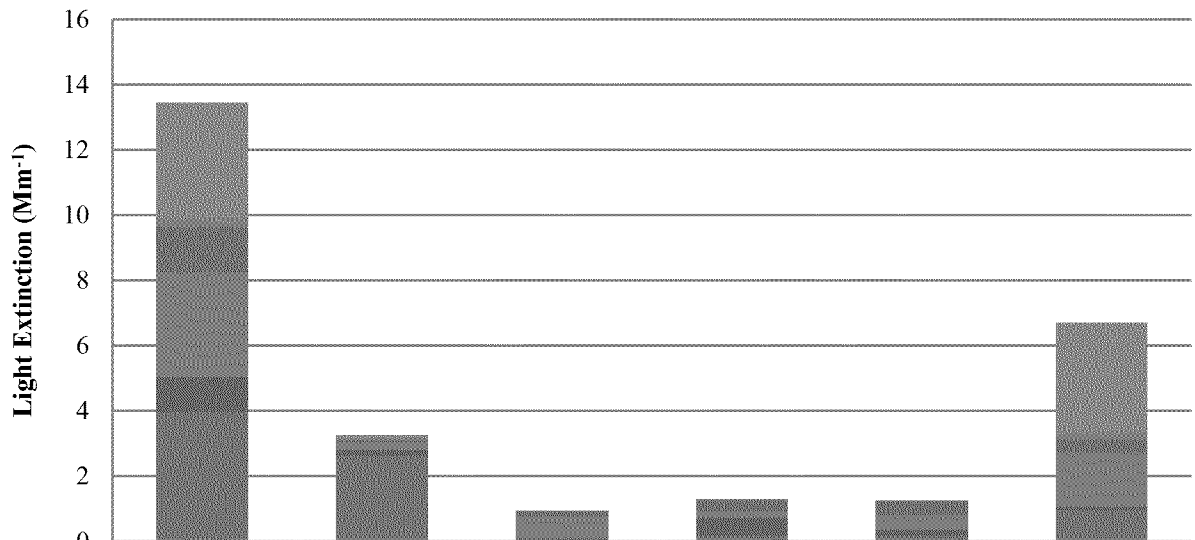
Figure 6 and Figure 7 show the relative contributions of sources within Arkansas to light extinction for each source category and species at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. SO_4 from Arkansas sources contributed approximately three percent of total modeled l extinction at Caney Creek and Upper Buffalo in 2002 on the twenty percent worst days. The point source category contributed approximately two thirds of the light extinction attributed to SO_4 from Arkansas sources at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. POA from Arkansas sources contributed approximately three percent and two percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo, respectively. Area sources were the primary driver of light extinction due to POA. NO_3 from Arkansas sources contributed approximately two percent and one percent to light extinction at Caney Creek and Upper Buffalo on the twenty percent worst days, respectively. On-road sources accounted for approximately fifty percent of the light extinction at Arkansas Class I areas attributed to Arkansas NO_3 sources. EC from Arkansas sources contributed approximately one percent and soil from Arkansas sources contributed approximately 0.2% to total light extinction at both Arkansas Class I areas on the twenty percent worst days. Attribution to light extinction from Arkansas sources of EC was split primarily among on-road, non-road, and area sources. Light extinction from Arkansas sources of soil was primarily attributed to area sources. CM from Arkansas sources, primarily area sources, contributed approximately one and two percent of total light extinction and Caney Creek and Upper Buffalo, respectively.

Figure 6 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.89	0.1	0.02	0.03	0.01	1.73
SOIL	0.27	0.03	0	0	0	0.23
EC	1.61	0.08	0.18	0.38	0.53	0.44
POA	3.54	0.33	0.74	0.21	0.64	1.62
NO3	2.11	0.36	0.12	1.09	0.35	0.18
SO4	4.14	2.94	0.03	0.17	0.17	0.83

Figure 7 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.53	0.13	0.01	0.03	0.02	3.34
SOIL	0.3	0.03	0	0	0	0.26
EC	1.39	0.06	0.16	0.33	0.45	0.4
POA	3.21	0.24	0.69	0.19	0.44	1.65
NO3	1.07	0.18	0.06	0.54	0.17	0.11
SO4	3.97	2.62	0.02	0.19	0.18	0.96

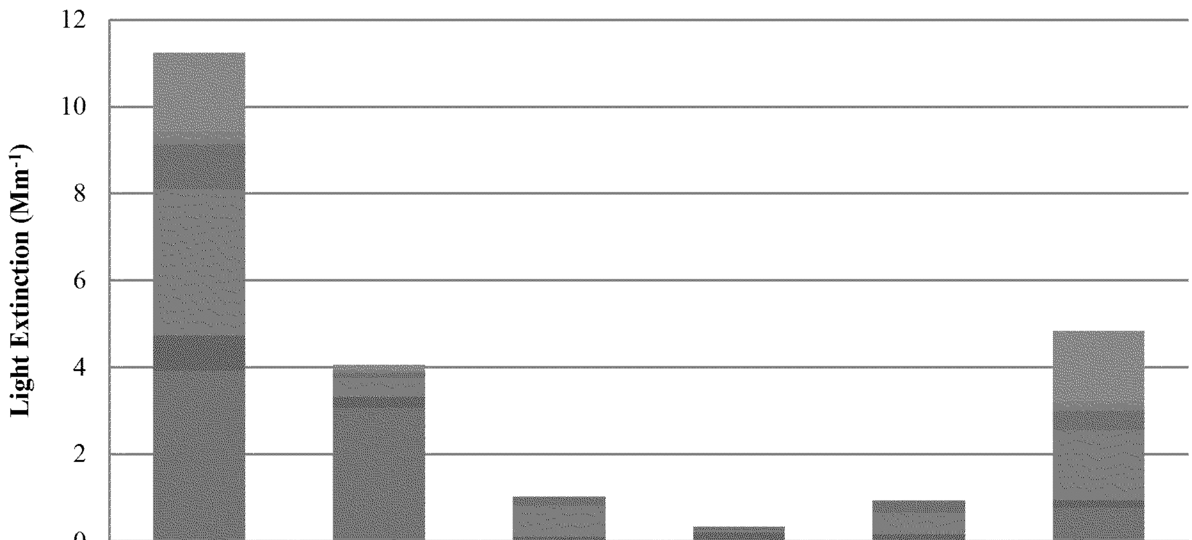
Table 8 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Area sources are projected to continue to have a larger impact on light extinction than do point sources when only sources located in Arkansas are considered. Area sources are projected to contribute approximately forty-three percent of light extinction attributed to Arkansas sources (six percent of total light extinction) at Caney Creek and fifty-four percent of light extinction attributed to Arkansas sources (eight percent of total light extinction) at Upper Buffalo. Point sources are projected to contribute approximately thirty-six percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Caney Creek and thirty percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Upper Buffalo. The other sources in Arkansas are projected to contribute between two percent and nine percent each to light extinction from Arkansas sources (0.3–1.2% of total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2018.

Table 8 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	4.05	1.04	0.35	0.95	4.85
Upper Buffalo	3.63	0.91	0.3	0.66	6.52

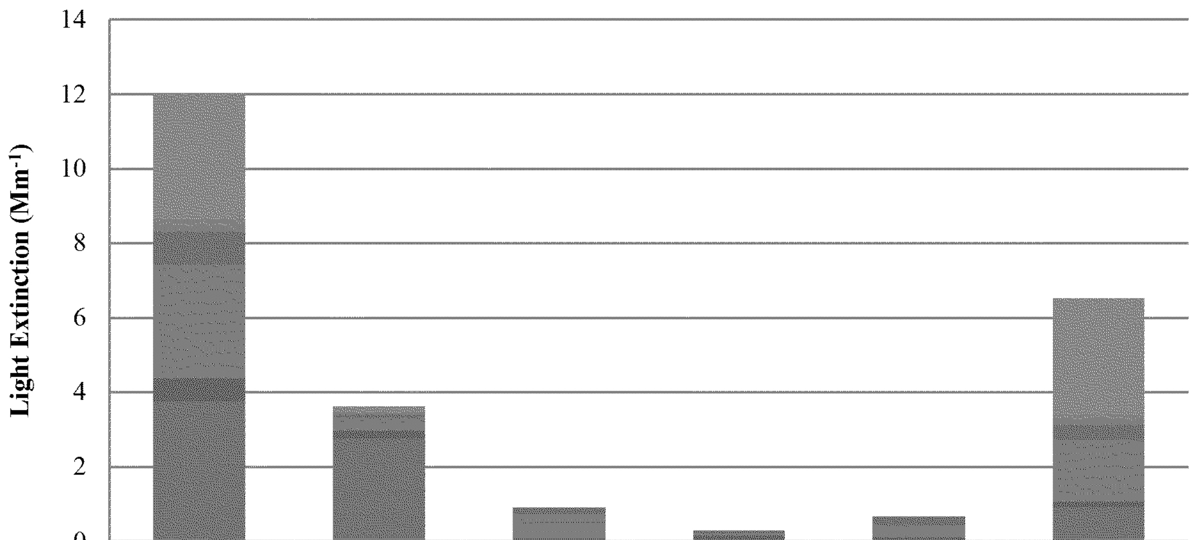
Figure 8 and Figure 9 show the relative contributions of sources within Arkansas to light extinction for each species and source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. According to the PSAT data for Arkansas sources, light extinction attributed to Arkansas NO_3 sources is projected to decrease by sixty-two percent at Caney Creek and by forty-one percent at Upper Buffalo. This projected decrease is largely due to a decrease in light extinction attributed to NO_3 from Arkansas on-road sources. Overall light extinction attributed to Arkansas sources of SO_4 are projected to decrease at Arkansas Class I areas; however, light extinction attributed to point sources of SO_4 located in Arkansas is projected to increase by four percent at Caney Creek and five percent at Upper Buffalo on the twenty percent worst days. Nevertheless, the contribution to total light extinction of SO_4 from Arkansas point sources remains relatively small—three percent of total light extinction at each Arkansas Class I area. Light extinction due to Arkansas sources of POA, EC, and CM are also projected to decrease. Light extinction due to Arkansas sources of soil is projected to increase; but, soil will remain the smallest Arkansas contributor to light extinction at both Arkansas Class I areas.

Figure 8 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.8	0.13	0.02	0.02	0.01	1.62
SOIL	0.3	0.06	0	0	0	0.23
EC	1.04	0.1	0.18	0.07	0.27	0.42
POA	3.36	0.45	0.72	0.05	0.5	1.63
NO3	0.81	0.25	0.08	0.18	0.13	0.16
SO4	3.93	3.07	0.03	0.02	0.03	0.78

Figure 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.36	0.17	0.01	0.03	0.01	3.14
SOIL	0.33	0.06	0	0	0	0.26
EC	0.89	0.08	0.16	0.06	0.21	0.39
POA	3.05	0.35	0.66	0.05	0.33	1.66
NO3	0.63	0.21	0.06	0.14	0.09	0.14
SO4	3.75	2.76	0.02	0.02	0.02	0.93

3. Summary of Key Pollutant and Source Category Findings

The region-wide PSAT data indicate that the relative contribution of SO_4 to light extinction at Arkansas Class I areas is much higher than for other pollutants on the twenty percent worst days. The majority of light extinction due to SO_4 can be attributed to point sources. The PSAT results for Arkansas sources illustrate that the relative contribution to light extinction of the various species from Arkansas sources is not as weighted toward SO_4 as the regional data set showed. Approximately a quarter of light extinction at Arkansas Class I areas resulting from sources located in Arkansas can be attributed to point sources of SO_4. Light extinction from all species associated with the point source category is smaller than for area sources when only sources located in Arkansas are considered. POA and CM are the primary species associated with area source contributions to light extinction.

After examining both region-wide PSAT data and data for Arkansas sources, ADEQ has identified SO_4 as the key species contributing to light extinction at Caney Creek and Upper Buffalo. Area sources do contribute a larger proportion of total light extinction when only sources located in Arkansas are considered; however, the cost-effectiveness for control of POA and CM species from many individual small sources is difficult to quantify. Only a small proportion of total light extinction is due to NO_3 from Arkansas sources and this proportion has historically been driven by onroad sources. NO_3 from Arkansas point sources contributed less than half a percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo based on 2002 PSAT data and is projected to contribute even less in 2018. Attribution of light extinction to soil and EC for Caney Creek and Upper Buffalo remain in both regional and Arkansas data sets.

The primary driver of SO_4 formation is emissions of SO_2 from point sources both region-wide and in Arkansas. As such, in this SIP ADEQ evaluates sources emitting at least 250 tons per year (tpy) of SO_2. These sources will be evaluated to determine whether their emissions and proximity to Arkansas Class I areas warrant further analysis using the four statutory factors.

B. Identification of Potential Reasonable Progress Sources for the First Planning Period

As a starting point to identifying which sources to evaluate for controls in ADEQ's reasonable progress analysis, ADEQ compiled a list of all sources that emitted at least 250 tpy of sulfur dioxide as reported to the EPA Emission Inventory System (EIS) in any given year between 2002 and 2015.[28] For those sources that participate in the Acid Rain Program, ADEQ obtained 2015 sulfur dioxide emissions from the Air Markets Program Data tool.[29] ADEQ then narrowed the list of sources to eleven sources that emitted at least 250 tons per year averaged over most recent three-year period for which data is available. These sources are listed in Table 9 below.

Table 9 Sulfur Dioxide Emissions from Sources Emitting Greater Than 250 Tons per Year

Facility	Most Recent Three-Year Period	Average Sulfur Dioxide Emissions (Tons Per Year)
Entergy White Bluff*	2014–2016	24,346
Entergy Independence	2014–2016	22,531
Flint Creek Power Plant (SWEPCO)*	2014–2016	5,350
Plum Point Energy Station Unit 1	2014–2016	2,759
FutureFuel Chemical Company	2013–2015	2,837
Domtar A.W. LLC, Ashdown Mill*	2013–2015	1,553
Evergreen Packaging-Pine Bluff	2013–2015	986
Albemarle Corporation-South Plant	2013–2015	1,382
SWEPCO- John W. Turk Jr. Power Plant	2014–2016	908
Ash Grove Cement Company/Foreman Cement Plant	2013–2015	369
Nucor-Yamato Steel Company	2013–2015	301

*Facilities are subject to BART requirements which satisfy the four factor analysis requirement for reasonable progress for these sources.

[28] Emissions Inventory datasets: 2002 National Emissions Inventory, 2005 National Emissions Inventory, 2008 National Emissions Inventory V3, 2009 Arkansas Department of Environmental Quality, 2010 Arkansas Department of Environmental Quality, 2011 National Emissions Inventory V2, 2012 Arkansas Department of Environmental Quality, 2013 Arkansas Department of Environmental Quality, 2014 National Emissions Inventory V1, and 2015 Arkansas Department of Environmental Quality.

[29] https://ampd.epa.gov/ampd/

Entergy White Bluff, Flint Creek, and Domtar are all subject to BART. Since the BART analyses conducted to establish BART control requirements are based on an assessment of many of the same factors that must be addressed in establishing the reasonable progress goals, these control requirements satisfy the reasonable progress goal-related requirements for review of these sources during this planning period. No additional emissions controls are necessary for these sources. For the other sources listed in Table 9, ADEQ calculated the total average actual emissions rate (Q) in tons of SO_2 per year over the most recent three-year period and determined the distance (D) in kilometers of each source to its closest Class I area. A Q divided by D value of ten was used as a threshold for further evaluation of reasonable progress controls. This value was selected based on guidance contained in the BART guidelines and is consistent with the approach used in other EPA rulemakings.[30] Table 10 lists the Q/D values for these sources.

Table 10 Q/D Values for Large SO_2 Point Sources[31]

Facility	Upper Buffalo	Caney Creek
Entergy Independence	126	81
Plum Point Energy Station Unit 1	9	7
FutureFuel Chemical Company	17	10
Evergreen Packaging-Pine Bluff	4	5
Albemarle Corporation-South Plant	5	9
SWEPCO- John W. Turk Jr. Power Plant	4	11
Ash Grove Cement Company/Foreman Cement Plant	1	5
Nucor-Yamato Steel Company	1	1

Three sources identified in Table 10 had a maximum Q/D value greater than or equal to ten: Entergy Independence, FutureFuel Chemical Company, and John W. Turk Jr. Power Plant. Entergy Independence is the second largest point source of SO_2 in Arkansas with average 2014–2016 emissions of 22,531 tpy. By contrast, FutureFuel Chemical Company averaged 2,837 tpy (2013–2015) and John W. Turk Jr. Power Plant averaged 908 tpy (2014–2016). SO_2 emissions from FutureFuel Chemical Company and John W. Turk Jr. Power Plant are approximately an order of magnitude lower than emissions from Entergy Independence. FutureFuel Chemical Company was a BART-eligible source and modeling performed in the development of the 2008 AR RH SIP demonstrated that FutureFuel Chemical Company had less than a 0.5 dv impact on Class I areas. John W. Turk Jr. Power Plant began operation in 2012 and has implemented best available control technology, which is more stringent than BART. As such, ADEQ determined that it was appropriate to defer consideration of these sources under reasonable progress to future regional haze planning periods. Deferring consideration of these two facilities is consistent with EPA's determination in the final AR RH FIP. ADEQ will focus its evaluation of the four

[30] 40 CFR part 51, app. Y, § III; Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule (February 18, 2014)
[31] Class I Areas_Q Over D Calculations.xls in Appendix F.

reasonable progress factors on Entergy Independence because it is the second highest emitter of SO_2 in Arkansas, has high Q/D values, and is not subject to BART.

C. Consideration of Reasonable Progress Factors for Entergy Independence

In determining reasonable progress, Clean Air Act section 169(A)(g)(1) requires states to examine the cost of compliance, the time necessary for compliance, energy and nonair impacts, and remaining useful life. In development of the AR RH FIP, EPA performed a reasonable progress analysis that considered two control technologies for Entergy Independence: Wet FGD and Dry FGD. Entergy provided additional information regarding EPA's analysis in comments on the AR RH FIP. Entergy also provided additional information with respect to costs associated with the use of LSC for Entergy White Bluff in an August 18, 2017 submittal. Our analysis below evaluates the statutory factors using the data provided by EPA in support of the AR RH FIP as supplemented by Entergy.

The Entergy Independence Power Plant is a coal-fired electric generating station with two identical 900 megawatt boilers. These boilers burn Wyoming Powder River Basin sub-bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as start-up fuel. The layout and boiler units used at this facility are similar to those used at Entergy White Bluff; however, units at Independence were installed in 1983, nine years after installation of units at Entergy White Bluff, and are not subject to BART. Because Entergy White Bluff and Entergy Independence are sister facilities, costs for different control technologies examined in the BART analysis for Entergy White Bluff should provide reasonably accurate cost and control efficiency estimates for Entergy Independence. This method of assessing cost of compliance for Entergy Independence is supported by documentation provided in the docket for the AR RH FIP.[32]

The available SO_2 retrofit control technology options for Entergy Independence Units 1 and 2 considered in the AR RH FIP and in this SIP revision are fuel switching to LSC, Dry FGD and Wet FGD. All three options are technically feasible. Fuel switching to coal with a sulfur content of 0.6 lb/MMBtu would result in a four to six percent reduction in SO_2 emissions from 2014–2016 levels.[33] Dry FGD systems have control efficiencies ranging from sixty to ninety-five percent. These systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter. Wet FGD, scrubbing the exhaust stream with a lime or limestone slurry, is capable of achieving eighty-to ninety-five percent control of SO_2 emissions.

1. Existing controls

Emissions of SO_2 from Entergy Independence units are currently controlled by the use of lower sulfur coals than required under current regulations. The new source performance standard for sulfur dioxide is 1.2 lb/MMBtu; however, a more stringent prevention of significant deterioration (PSD) emissions limitation of 0.93 lb/MMBtu is in effect for these units. Entergy Independence

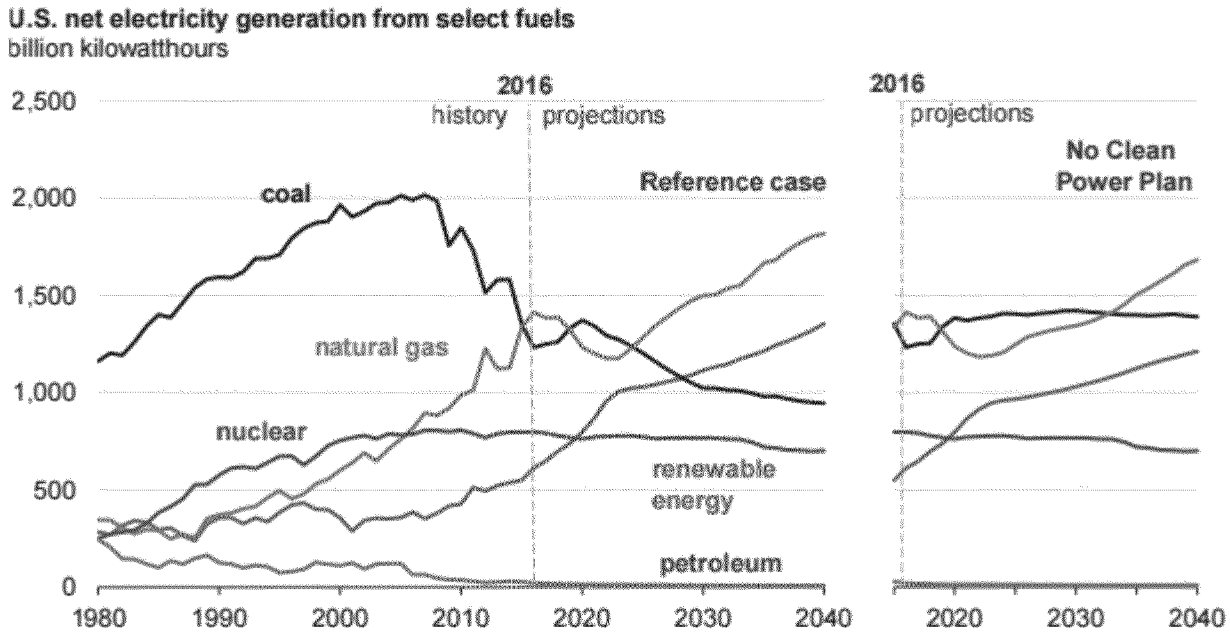
[32] EIA Consolidated Data_WB and Ind_Y2012.xlsx in Appendix F
[33] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during 2009–2013 to a 0.6 lb/MMBtu limit for low sulfur coal. This baseline was selected to match the EPA baseline used to calculate control efficiency and cost-effectiveness values for Dry FGD and Wet FGD.

has been able to achieve 30-boiler-operating-day average emissions rates in the range of 0.48–0.63 lb SO_2/MMBtu.[34] The 30-boiler-operating-day average monthly emissions rate between 2014 and 2016 was 0.57 lb SO_2/MMBtu at Unit 1 and 0.56 lb SO_2/MMBtu at Unit 2. Entergy Independence Units 1 and 2 are currently permitted to emit 35,438.6 tons per year (tpy) of SO_2 (8,091.0 lb SO_2/hr) each or 70,877.2 tpy of SO_2 (16,182 lb SO_2/hr) combined.[35] Annual emissions for Entergy Independence Units 1 and 2 combined from 2008–2014 ranged from 26,448–32,974 tpy SO_2—less than half of total allowable emissions in their permit.[36] Annual emissions from Entergy Independence dropped to 14,994 tpy SO_2 in 2015—less than a quarter of total allowable emissions in their permit.[37] Annual emissions from Entergy Independence increased to 22,569 SO_2 in 2016, but are lower than any annual emissions rate from 2008–2014.[38]

Market trends for coal and natural gas have resulted in decreased dispatch of Entergy Independence. According to data from the Energy Information Administration, the economic pressure on coal units due to low natural gas prices is expected to continue throughout the rest of the 2008–2018 planning period and beyond.[39] Figure 10 shows energy consumption trends from the electricity sector by fuel from 1980–2016 and projects trends out to 2040. Taken together, the decrease in dispatch and the use of lower sulfur coals have resulted in reduced emissions from Entergy Independence.

[34] Air Markets Program Data: Monthly Heat Input and SO_2 Data for Entergy Independence for 2014-2016 <https://ampd.epa.gov/ampd/>
[35] Entergy Arkansas, Inc. – Independence, Permit No. 0449-AOP-R10 AFIN: 32-00042
[36] 2009 Arkansas Department of Environmental Quality Emissions Inventory, 2010 Arkansas Department of Environmental Quality Emissions Inventory, 2011 National Emissions Inventory Version 2, 2012 Arkansas Department of Environmental Quality Emissions Inventory, 2013 Arkansas Department of Environmental Quality Emissions Inventory, 2014 National Emissions Inventory Version 1 <https://eis.epa.gov/eis-system-web>
[37] Air Markets Program Data: Air Markets Program Data: Annual SO_2 Data for Entergy Independence for 2015 <https://ampd.epa.gov/ampd/>
[38] Air Markets Program Data: Air Markets Program Data: Quarterly SO_2 Data for Entergy Independence for 2015 and 2016 <https://ampd.epa.gov/ampd/>
[39] *Annual Energy Outlook 2017*. U.S. Energy Information Administration

Figure 10 United States Electricity Sector Energy Consumption by Fuel[40]



2. Cost of Compliance

In the AR RH FIP, EPA estimated cost-effectiveness for the Dry FGD and Wet FGD for Entergy Independence based on five-factor BART analysis for White Bluff. Entergy provided different cost-effectiveness for Dry FGD estimates in their comments on the AR RH FIP. ADEQ calculated cost information using information provided by Entergy regarding LSC cost premiums, U.S. Energy Information Administration fuel consumption data, and EPA Air Markets Program Data.

Fuel switching to LSC has no associated capital costs; however, there is a cost premium associated with guaranteeing that the sulfur content is below 0.6 lb/MMBtu.[41] ADEQ estimated annualized operation and maintenance costs of switching to LSC at $1.5 million and $1.6 million for Entergy Independence Unit 1 and Unit 2, respectively.[42] Controlled annual emission rates for the LSC scenario were calculated based on these annualized costs and the anticipated emission reductions from switching to LSC.[43] ADEQ estimated that the average cost-effectiveness for fuel

[40] U.S. Energy Information Administration. (2017). Annual Energy Outlook 2017 at70. <http://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

[41] The Entergy August 18, 2017 revised BART analysis for White Bluff estimated this cost premium at $0.50/ton.

[42] Annualized capital costs were calculated using average annual fuel consumption in tons multiplied by the $0.50/ton cost premium Entergy quoted for low sulfur coal in their August 18, 2017 revised BART analysis for White Bluff. Annual fuel consumption date was obtained from U.S. Energy Information Administration Form EIA-923 detailed data for 2009–2013.

[43] The control efficiency for low sulfur coal for each unit was calculated based on the difference between the maximum 30-boiler operating day rolling average emission rate during the 2009–2013 baseline period and the controlled emission rate. The controlled annual emissions rate was calculated based on the percent decrease in 30-boiler operating day emission rate from the maximum emission rate achieved by low sulfur coal.

switching to LSC is approximately \$2,284/ton of SO_2 reduced at Entergy Independence Unit 1 and \$2,173/ton of SO_2 reduced at Entergy Independence Unit 2.

Installation of Wet FGD requires a large capital investment. EPA estimated total annualized costs of Wet FGD at \$49,526 for each Entergy Independence unit based on a thirty-year amortization period. EPA estimated that the average cost-effectiveness for Wet FGD was \$3,706 per ton of SO_2 reduced at Entergy Independence Unit 1 and \$3,416 per ton of SO_2 reduced at Entergy Independence Unit 2. In the AR RH FIP, EPA eliminated Wet FGD due to the high incremental cost and the minimal incremental increase in estimated visibility improvement achieved over Dry FGD.

Installation of Dry FGD also requires a large capital investment. EPA estimated total annualized costs of Dry FGD at \$36,842,543 for each Entergy Independence unit based on a thirty-year amortization period.[44] EPA estimated that the average cost-effectiveness for Dry FGD was \$2,853 per ton of SO_2 reduced at Entergy Independence Unit 1 and \$2,634 per ton of SO_2 reduced at Entergy Independence Unit 2. In comments on the AR RH FIP, Entergy provided different cost-effectiveness estimates for Dry FGD, assuming that the costs at Entergy Independence match the cost of installation and operation at Entergy White Bluff. Entergy's estimates were \$4,234/ton of SO_2 removed at Entergy Independence Unit 1 and \$3,909 per ton of SO_2 removed at Entergy Independence Unit 2.[45] Table 11 lists ADEQ's estimates of cost-per-deciview for Dry FGD controls at Independence Units 1 and 2 for each Class I area

Table 11 Average Dollar-Per-Deciview Reduction for Control Options at Independence Units 1 and 2[46]

	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
SDA	\$67,230,917	\$62,551,006	\$69,777,543	\$70,512,043

3. Time Necessary for Compliance

The typical time necessary for compliance for either add-on technology—Dry FGD or Wet FGD—is five years. Entergy estimates that the time necessary to comply with a limit based on LSC is three years due to time left on existing coal supply contracts, the time required to burn through current fuel stocks, and the time needed to build up a stockpile of LSC to assure against possible fuel supply disruptions.

[44] EPA calculated cost-effectiveness based on allowed costs and alternative cost-effectiveness values including disallowed costs proposed by Entergy. The costs included in this SIP exclude disallowed costs. Calculations of these costs can be found in the Independence SDA Costs spreadsheet included in Appendix F.
[45] Entergy Arkansas Inc. (2015). Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas. Docket ID No. EPA-R06-OAR-2015-0189
[46] Total Annualized Cost of Dry FGD for Independence from the AR RH FIP divided by the deciview impact of Dry FGD as revised on May 1, 2015. Calculations of dollars-per-deciview can be found in the Independence SDA Costs spreadsheet included in Appendix F.

4. Energy and Nonair Quality Environmental Impacts of Compliance

Dry FGD utilizes lime slurry to remove SO_2 from flue gas. In the process, particulate matter is generated that must be controlled through use of a baghouse or electrostatic precipitator. Once collected, the waste material is disposed of through landfilling. Costs associated with control of particulate matter and additional power requirements were factored into the cost estimates calculated by Entergy and EPA. Entergy has not indicated unusual circumstances that would create greater problems than experienced elsewhere that Dry FGD was utilized as BART.

5. Remaining Useful Life

There are no State or federally enforceable limitations on continued operations at Entergy Independence; therefore, cost of compliance calculations are based upon a thirty-year amortization period for Dry and Wet FGD. However, given market trend for coal and the age of Entergy Independence, Entergy may choose to change operations at Entergy Independence thus not realizing a full thirty-year amortization period for Dry and Wet FGD.

6. Degree of Improvement in Visibility

Although the degree of visibility improvement is not one of the four statutory factors for a reasonable progress analysis, the ultimate goal of any reasonable progress controls should be achieving visibility improvements. In the AR RH FIP, EPA estimated that installation of Dry FGD at Entergy Independence Unit 1 and Unit 1 would achieve a 1.096 dv improvement at Caney Creek and a 1.178 dv improvement at Upper Buffalo. In comments on the AR RH FIP, Entergy disagreed with EPA's estimates of visibility improvements that would be achieved from installation of Dry FGD at Entergy Independence. Using CAMx, a photochemical model, instead of the CALPUFF model used by EPA, Entergy estimated that installation of Dry FGD at Independence would only result in a 0.08 dv improvement at Caney Creek and a 0.07 dv improvement at Upper Buffalo on the twenty percent worst days.[47] A value of one dv is considered perceptible. Because Entergy Independence frequently achieves the less than or equal to the 0.6 lb/MMBtu emission rate associated with LSC, ADEQ has not modeled visibility impacts for the LSC scenario.

D. Additional Controls Necessary for Reasonable Progress at Arkansas Class I Areas

Based on this analysis, ADEQ has determined that no add-on controls for SO_2 or PM beyond BART are necessary for reasonable progress during the 2008–2018 planning period. The Arkansas NOx Regional Haze SIP submitted to EPA required compliance with the CSAPR trading program for ozone season NOx for all Arkansas EGUs participating in that program to address control of NOx for reasonable progress.

Through an evaluation of emissions and distance from wilderness areas, ADEQ determined that only Entergy Independence need be considered in a four factor analysis; however, ADEQ has determined that installation of add-on control technologies, as was finalized in the AR RH FIP, is

[47] Entergy Arkansas Inc. (2015). Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas. Docket ID No. EPA-R06-OAR-2015-0189

neither reasonable nor necessary to achieve reasonable progress for the 2008–2018 planning period. Both Entergy's and EPA's cost-effectiveness estimates for Dry FGD at Entergy Independence exceed screening thresholds used for cost-effectiveness in other approved reasonable progress analyses.[48] Furthermore, the significant capital investment costs of Dry FGD would lock Entergy into continued operation of the aging Entergy Independence for thirty years in order to avoid stranded costs associated with the installation of Dry FGD. Although fuel switching to LSC has a similar cost-effectiveness in terms of emission reductions as does Dry FGD, fuel switching to LSC requires no capital costs and locks in visibility improvements already observed at Arkansas and Missouri Class I areas due to Entergy's choice to burn lower sulfur content coals than required by permit at Entergy Independence Unit 1 and Unit 2. Requiring a technology that does not involve a significant capital investment that must be amortized over a long period also provides Entergy with the flexibility to determine the continued viability of Entergy Independence based on market conditions rather than extending the possible life of the units based on the need to recover the capital costs of Dry FGD. Entergy has also proposed their willingness to commit to using only LSC at Entergy Independence in comments on the AR RH FIP.[49] Therefore, it is reasonable and consistent with EPA guidance to defer more expensive controls to later planning periods in order to maintain a consistent glidepath toward the long-term goal. [50] As such, ADEQ has determined that it is appropriate to require Entergy Independence to meet a 0.6 lb SO_2/MMBtu limit based on LSC to ensure that the visibility progress achieved during this planning period continues.

In communication with ADEQ, Entergy indicated that it is their practice to project how much coal will be needed in future years and to contract for a portion of their coal supply up to three years in advance. Furthermore, Entergy keeps a reserve supply of coals at Independence to ensure that the units can operate in the event of a fuel supply disruption. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.6 lb SO_2/MMBtu at Entergy Independence Unit 1 and Unit 2 no later than three years after approval of this SIP revision.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's determination.

E. Reasonable Progress Goals for Arkansas Class I Areas

ADEQ is revising the RPGs established in the 2008 AR RH SIP for the twenty percent worst days at Caney Creek and Upper Buffalo to reflect control measures included in this SIP revision and the revision proposed in July 2017 that are required to be in effect by the end of the first planning period. In order to provide RPGs that account for emissions reductions from SIP controls, we have used a method similar to that used by EPA for the AR RH FIP. This method is

[48] Approval and Promulgation of Air Quality Implementation Plans; Common Wealth of Kentucky; Regional Haze State Implementation Plan: Proposed Rule (2011). 76 FR 78194
EPA approved RPGs in Kentucky SIP based on CAIR, which had a $2000/ton SO_2 cost-effectiveness screening threshold.
[49] Entergy Arkansas Inc. Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas (August 8, 2016)
[50] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program at page 1-4

based on a scaling of light extinction components in proportion to emissions changes anticipated from SIP controls for which compliance is required on or before December 31, 2018. ADEQ is not revising its goal of no degradation on the twenty percent best days included in the 2008 AR RH SIP.

Using the same formulas EPA used to develop its RPGs for the AR RH FIP, ADEQ scaled CENRAP's CAMx 2018 projection of light extinction components for SO_4 and NO_3 in proportion to the SIP revision's emissions reductions for SO_2 and NOx, respectively. ADEQ made updates to reflect the most recent three years of data for emissions and heat input for Arkansas EGUs. The most recent three years of data (2014–2016) were used as opposed to EPA's method of using the five most recent years of data minus the minimum and maximum values (2009–2013) to ensure that recent changes in dispatch of Arkansas EGUs were captured.[51] The results of our analysis for the twenty percent worst days for 2018 for Caney Creek and Upper Buffalo are included in Table 12.[52]

Table 12 Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I Area	2018 RPG 20% Worst Days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

Figure 11 and Figure 12 demonstrate that Arkansas is already achieving greater visibility improvements than the RPGs listed in Table 12.

[51] EIA projections show decreased consumption of coal by electric generating units that is expected to continue through 2040. Therefore, ADEQ anticipates that the coal EGU dispatch trends seen in the most recent three years is likely to continue through the first regional haze planning period and the next two planning periods. See Figure 10

[52] See RPG Calculation Data Sheet provided at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

Figure 11 Caney Creek Reasonable Progress Assessment – 20% Worst Days

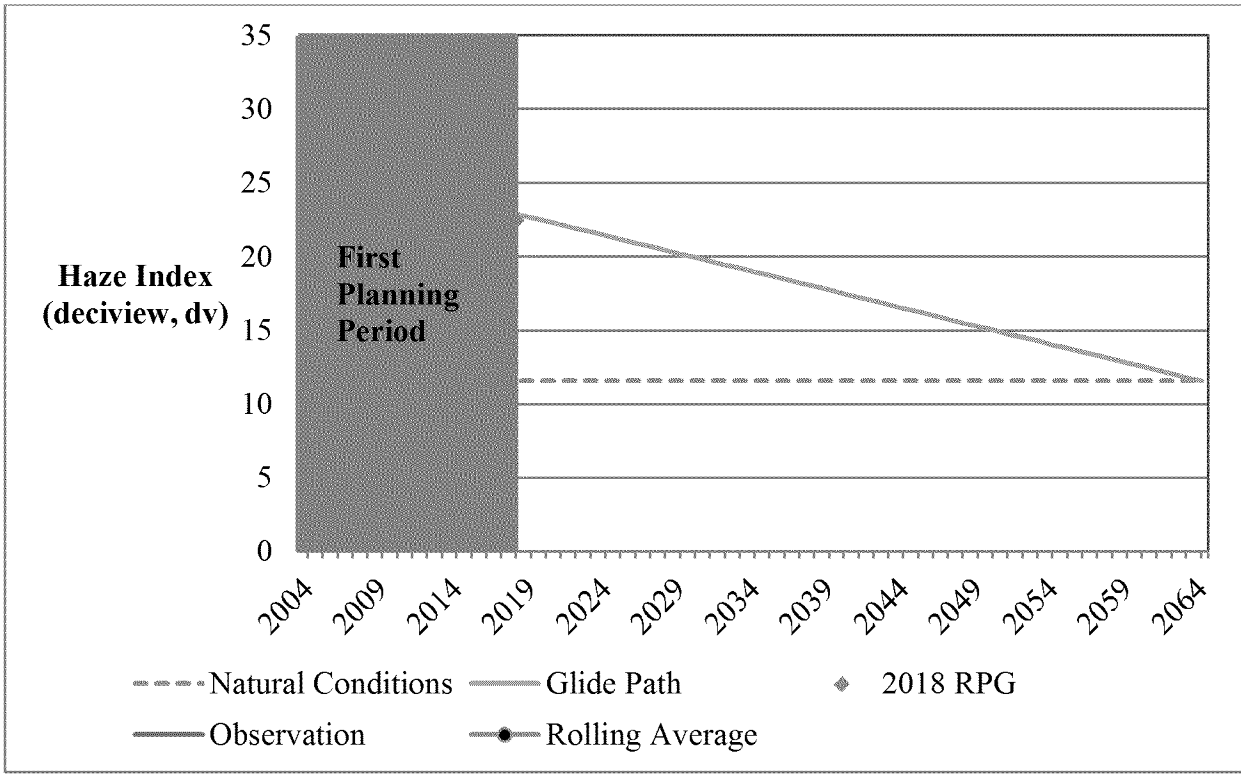
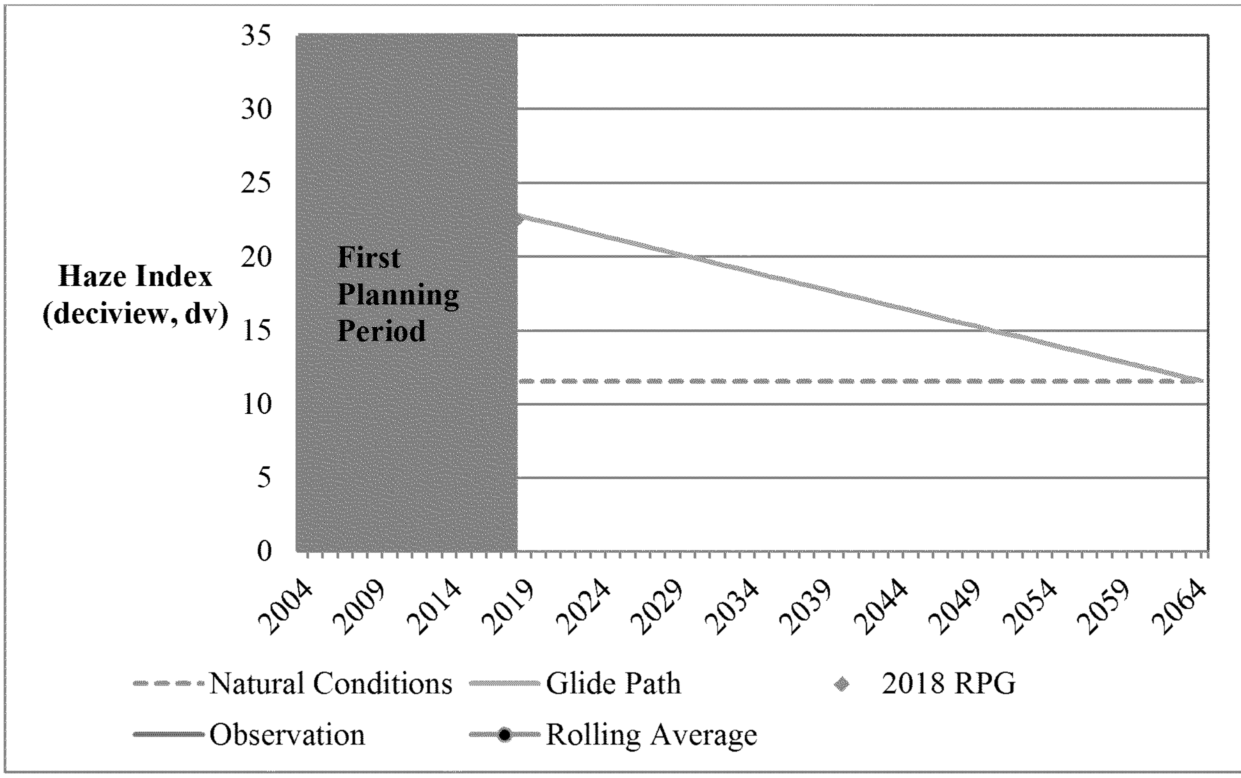


Figure 12 Upper Buffalo Reasonable Progress Assessment – 20% Worst Days



F. Interstate Visibility Transport

Sources in Arkansas impact two Class I areas in Missouri: Hercules Glade and Mingo. CENRAP PSAT data indicates that Arkansas sources contributed approximately seven percent of light extinction at Hercules Glades and four percent of light extinction at Mingo. The impact of Arkansas sources are projected to increase between 2002 and 2018 to approximately nine percent of total light extinction at Hercules Glades and five percent at Mingo based on the CENRAP PSAT data.

Figure 13 and Figure 14 demonstrate that Missouri is on track to achieve its visibility goals. In Missouri's 2009 Regional Haze SIP, Missouri established 2018 reasonable progress goals of 23.71 dv for Mingo and 23.06 for Hercules Glades. The most recent calculations for the twenty percent haziest days and twenty percent best days for Class I areas were performed for 2015.[53] For both Mingo and Hercules Glades, visibility impairment on the twenty percent haziest days in 2015 beat Missouri's 2018 RPGs for both Class I areas. The most recent five-year rolling average of observed visibility impairment on the twenty percent haziest days at Hercules Glades beat Missouri's 2018 RPG for that Class I area and the most recent five year-rolling average of observed visibility impairment on the twenty percent haziest days at Mingo is on track to beat

53 http://vista.cira.colostate.edu/DataWarehouse/IMPROVE/Data/SummaryData/RHR_2015/SIA_group_means_7_16.csv

Missouri's RPG for that Class I area. The visibility progress observed indicates that sources in Arkansas are not interfering with the achievement of Missouri's RPGs for Hercules Glades and Mingo. Therefore, no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met. The control measures contained in the 2008 AR RH SIP, the NOx Regional Haze SIP revision, and this SIP revision satisfy the interstate transport visibility requirement of CAA 110(a)(2)(D)(i)(II) for the 2008 eight-hour ozone and 2012 annual $PM_{2.5}$ NAAQS.

Figure 13 Hercules Glades Reasonable Progress Assessment – 20% Worst Days

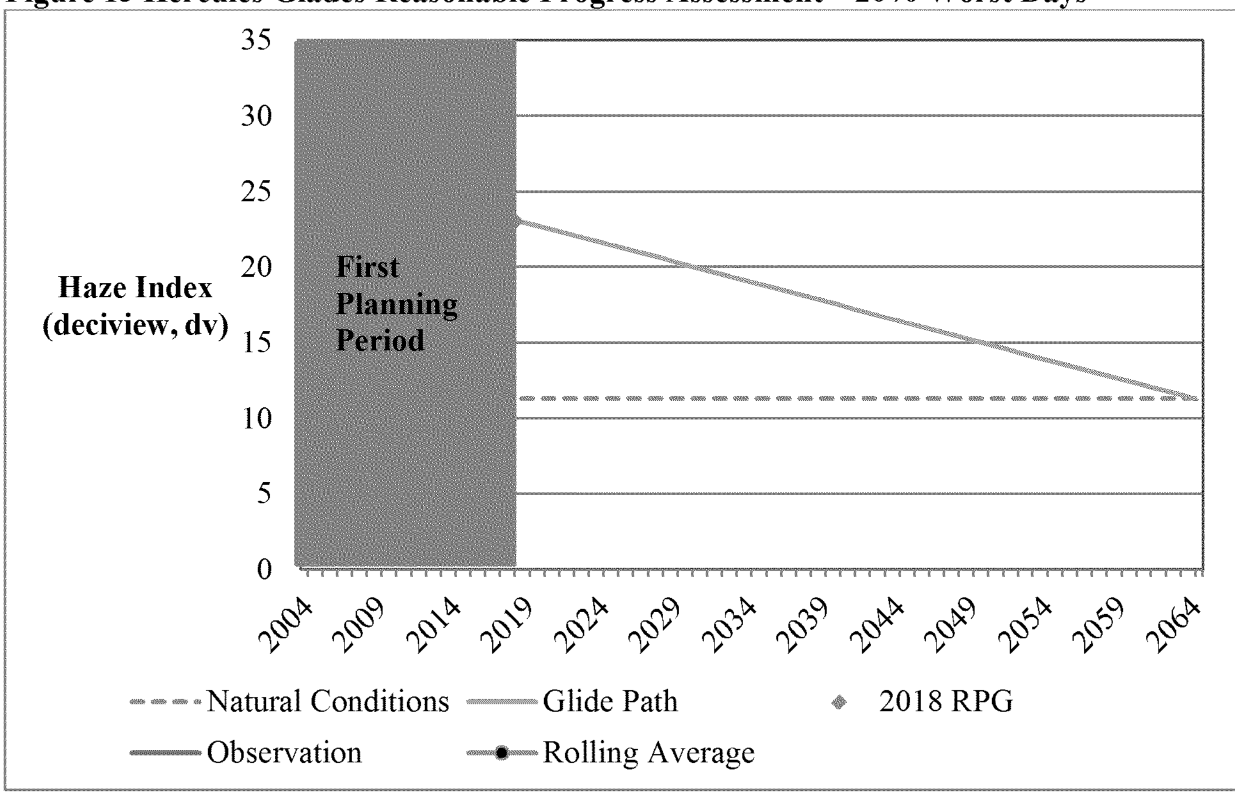
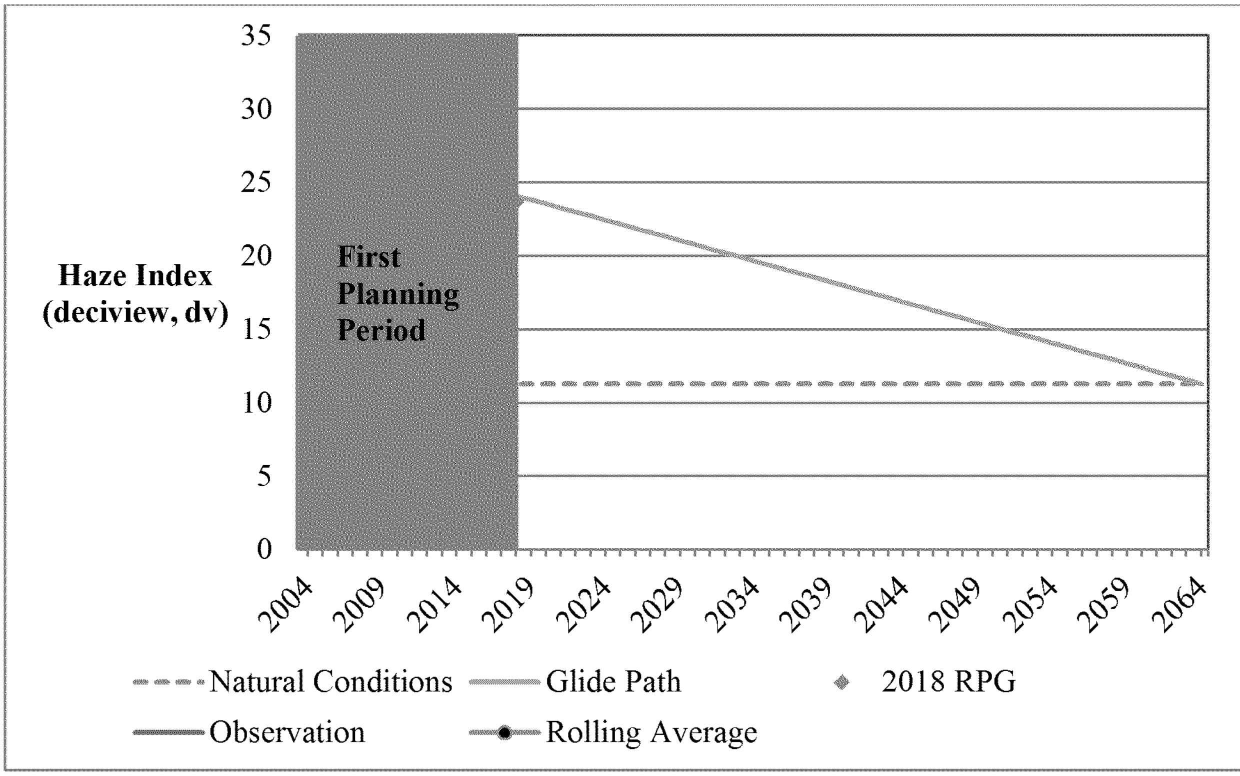


Figure 14 Mingo Reasonable Progress Assessment – 20% Worst Days



VI. Long-Term Strategy

In 2012, EPA partially approved and partially disapproved Arkansas's long-term strategy included in the 2008 AR RH SIP. 40 CFR 51.308(d)(3)(v) requires the consideration of the following factors in developing a long-term strategy: (1) Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Because EPA disapproved some of ADEQ's BART determinations and RPGs, EPA disapproved the emissions limitations and schedules of compliance element of the long-term strategy included in the 2008 AR RH SIP. EPA approved the other six elements of the long-term strategy.

Because the ongoing air pollution programs element of the Arkansas long-term strategy was previously approved, ADEQ is not proposing changes to that element in this SIP revision. Nevertheless, ADEQ notes that the landscape of ongoing air pollution programs has changed since EPA approved that element of the long-term strategy in the 2008 AR RH SIP. These changes include more stringent vehicle emission standards, renewable fuel standards, fuel efficiency standards, marine and aircraft standards, mercury and air toxics standards, various national emission standards for hazardous air pollution, and a replacement for the clean air interstate rule in the form of CSAPR. These additional air pollution programs are anticipated to achieve even greater emissions reductions that may result in further visibility improvement than the programs described in the 2008 AR RH SIP. A partial list of ongoing air pollution programs that have been implemented since the 2008 AR RH SIP is provided below:

- Tier 3 Vehicle Emissions and Fuel Standards Program (light duty, medium duty, and some heavy duty) (79 FR 23414, 2014)
- 2017 and Later Model Year CAFÉ Standards (77 FR 62624, 2012)
- Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017 (80 FR 77420, 2015)
- Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy Duty Engines and Vehicles (76 FR 57106)
- Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2 (81 FR 73478, 2016)
- Ocean-going vessels category 3 marine rule (2010), NOx standards for Aircraft (2012)
- Small Nonroad Engine and Marine Spark-Ignition Engines and Vessels Emission Standards Phase 3 (2008)
- New NAAQS standards: 2006 $PM_{2.5}$, 2008 Ozone, 2010 NO_2, 2010 SO_2, 2012 $PM_{2.5}$
- Mercury and Air Toxics Standards
- CSAPR and CSAPR update
- NESHAP for Primary Aluminum Reduction Plants (80 FR 62390, 2015)
- NESHAP for Secondary Aluminum Production (80 FR 56700, 2015)
- NESHAP for Phosphoric acid manufacturing and phosphate fertilizer production (80 FR 50386, 2015)
- NESHAP for Mineral Wool Production and Wool Fiberglass manufacturing (80 FR 45280, 2015)
- NESHAP for Ferroalloys Production (80 FR 37366, 2015)
- NESHAP for Off-site waste and recovery operations (80 FR 14248, 2015)
- NSPS update for New Residential Wood Heaters, New Residential Hydronic Heaters, and Forced-Air Furnaces (80 FR 13672, 2015)
- NSPS update for Kraft Pulp Mills (79 FR 18952, 2014)
- NESHAP for Group IV Polymers and Resins; Pesticide Active Ingredient Production; and Polyether Polyols production (79 FR 17340, 2014)
- NESHAP and NSPS for Portland cement Manufacturing Industry (78 FR 10006, 2013)
- NESHAP for Hard and Decorative Chromium Electroplating and Chroming Anodizing Tanks and NESHAP for Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants (77 FR 58220, 2012)
- NSPS and NESHAP for Oil and Natural Gas Sector (77 FR 4940, 2012)
- NSPS for Nitric Acid Plants (77 FR 48433, 2012)
- Greenhouse Gas Tailoring Rule Step 3 and Plantwide Applicability Limits (77 FR 41051, 2012)

- NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units and NSPS for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small-Industrial-Commercial-Institutional Steam Generating Units (77 FR 9304, 2012)
- NESHAP for Secondary Lead Smelting (77 FR 556, 2012)
- NESHAP for Wood Furniture Manufacturing Operations revision (76 FR 72050, 2011)
- NESHAP for Primary Lead Processing (76 FR 70834, 2011)
- NESHAP for Marine Tank Vessel Loading Operations and NESHAP for Group I Polymers and Resins (76 FR 22566, 2011)
- NESHAP for Major Sources Industrial, Commercial, and Institutional Boiler and Process Heaters (76 FR 15608, 2011)
- Source Determination for Certain Emissions Units in the Oil and Natural Gas Sector (81 FR 35622, 2016)

ADEQ also acknowledges planned changes in operations at large stationary sources that have historically impacted Arkansas Class I areas. Specifically, ADEQ anticipates further reductions in visibility impairment due to recent announced closures of power plants in Texas. In October 2017, Luminant announced retirement in 2018 of three large power plants in Texas: Big Brown Plant, Sandow Plant, and Monticello Plant.[54] Both Big Brown Plant and Monticello Plant impact visibility at Caney Creek.[55] The baseline maximum visibility impact from Big Brown at Caney Creek is 3.775 dv and the baseline maximum visibility impact from Monticello at Caney Creek is 10.498 dv.[56]

In this SIP revision, ADEQ has addressed the disapproved BART determinations for all subject-to-BART sources in Arkansas, with the exception of Domtar Ashdown Mill, and reasonable progress determinations. BART determinations are summarized in Section IV of this SIP and additional technical supporting data are found in Appendices B–E. Emissions limitations and schedules of compliance are rendered enforceable by AOs. BART requirements and compliance schedules for Domtar Ashdown Mill are included in the AR RH FIP. The long-term strategy and RPGs are reflective of those federally enforceable AR RH FIP controls for Domtar. Therefore, ADEQ requests that EPA fully approve Arkansas's revised long-term strategy.

VII. Review, Consultations, and Comments

A. EPA Review with Parallel Processing

The State of Arkansas plans to submit this proposed SIP revision, along with a request for parallel processing and a draft notice of public hearing and opportunity for comment, to EPA. Arkansas also requested that EPA stay the NOx emissions limitations for EGUs contained in the AR RH FIP during EPA's review of this SIP revision and withdraw such limitations upon

[54] https://www.luminant.com/luminant-announces-decision-retire-monticello-power-plant/; https://www.luminant.com/luminant-close-two-texas-power-plants/

[55] Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Proposed Rule (82 FR 912, January 4, 2017)

[56] Id. Table 15 at 931

approval of this SIP revision. The request for parallel processing has been included in Tab A of this proposed SIP package.

B. Federal Land Manager Consultation

In accordance with the provisions of 40 C.F.R. § 51.308(i)(2), ADEQ will consult with the designated FLM staff personnel. This consultation will give FLMs the opportunity to discuss their assessment of the impact of the proposed SIP revisions on Arkansas Class I areas——Upper Buffalo and Caney Creek—and other Class I areas.

On October 27, 2017, ADEQ submitted letters to notify the federal land manager staff of this proposed SIP revision and to provide them with electronic access to the revision and related documents. Any comments received from the FLMs will be considered and posted to ADEQ's Regional Haze webpage: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx. The FLM contact list and notification letters are included in Tab E of this proposed SIP package. Comments from FLMs and responses will be included in the final SIP package

C. Consultation with States

For the 2008 AR RH SIP, ADEQ engaged in extensive interstate consultation with states participating in the CENRAP RPO. Because Missouri has two Class I areas impacted by Arkansas sources, ADEQ submitted a letter on October 27, 2017 to Missouri Department of Natural Resources (DNR) air pollution control program staff to notify them of this proposed SIP revision and to provide them with electronic access to the revision and related documents. Any comments received from Missouri DNR will be considered and posted to ADEQ's Regional Haze webpage. The notification letter is included in Tab E of this proposed SIP package. Comments from Missouri DNR and responses will be included in the final SIP package.

D. Public Review

ADEQ will provide notice of a public hearing to receive public comments on this proposed SIP revision. The notice of the proposal and public hearing will be published in the Arkansas Democrat Gazette, which is a newspaper in circulation statewide, at least thirty days prior to the public hearing and will be posted on ADEQ's website concurrently with newspaper publication of the public notice. The notice will provide logistical information regarding the public hearing and the length of the public comment period. The public comment period for this SIP revision will be at least thirty days in accordance with notice requirements under 40 C.F.R. §51.102.

The notice contains information on the availability of the proposed SIP revision for public inspection at ADEQ information depositories, ADEQ headquarters, and ADEQ's Regional Haze webpage.

Both oral and written comments received by ADEQ during the public comment period will be posted on the ADEQ Regional Haze web page. Copies of written comments, a summary of ADEQ's response to comments, and records from the public hearing will be included in the final SIP package.

VIII. Conclusion

With the NOx Regional Haze SIP submission and this SIP submission together, ADEQ has addressed all disapproved elements of the 2008 AR RH SIP, with the exception of requirements for Domtar Ashdown Mill. The compliance obligations for Domtar under the AR RH FIP are currently the subject of litigation and ADEQ supports Domtar's efforts to demonstrate that, due to their changes in operation, no BART emission limits are necessary as a result of emission reductions achieved from their conversion of the Ashdown Mill to fluff pulp production. ADEQ commits to continuing to work with Domtar to ensure that credit is given for their success in reducing emissions and thereby their impacts on visibility. Arkansas requests that EPA withdraw the elements of the AR RH FIP addressed in this SIP revision and review and approve this SIP revision, the NOx Regional Haze SIP revision, and Arkansas's "State Implementation Plan Review for the Five-Year Regional Haze Progress Report" submitted in 2015 as expeditiously as possible.

APPENDIX A
Additional Information Regarding BART Screening for Georgia-Pacific Crossett Mill

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APPENDIX F
Reasonable Progress Analysis Technical Supporting Information and Data Sheets

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Excel files have been converted to PDF and included with the SIP in Appendix F Tabs 2–7. For questions or requesting copies of Excel files, contact Tricia Treece via email at treecep@adeq.state.ar.us or by phone at 501-682-0055.

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